Framework and approach

Ausgrid, Endeavour Energy and Essential Energy Regulatory control period commencing 1 July 2019

July 2017

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	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 2019 to 30 June 2024
opex	operating expenditure
RAB	regulatory asset base
ROLR	retailer of last resort

Shortened Form	Extended Form
STPIS	service target performance incentive scheme

Overview

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).

Ausgrid, Endeavour Energy and Essential Energy operate monopoly electricity distribution networks in New South Wales (NSW). The networks comprise the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. The three NSW network businesses design, construct, operate and maintain the distribution networks for NSW electricity consumers.

We make regulatory decisions on the revenues the NSW network businesses can recover from their customers. We determine their revenue by an assessment of their efficient costs and forecasts. Our assessment is based on regulatory proposals submitted by the network businesses in advance of a regulatory control period, in this case beginning 1 July 2019. 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.

The Framework and Approach (F&A) is the first step in a two year process to determine efficient prices for electricity distribution services in NSW. 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.

Five years ago we published an F&A for the NSW distributers for the current regulatory control period. For the 2019–24 regulatory control period we consider it prudent to review the current NSW F&A paper. Changes to the NER in November 2012 introduced new incentive schemes and allowed us to adopt improved approaches to assessing expenditure forecast by the network service providers.[1] The Power of Choice reforms also introduced changes to

1 Which we outline in our published guidelines. These guidelines are available at www.aer.gov.au/Better-regulation-reform-program.

metering contestability.[2] Further, we are currently developing a new demand management incentive scheme (DMIS) and innovation allowance mechanism (Allowance Mechanism)[3] and have recently published a national ring-fencing guideline.[4]

Before reaching our proposed approach, we published a preliminary F&A for the NSW distributors on 10 March 2017, seeking submissions from interested parties. Submissions closed on 21 April 2017, with 12 responses received, including a submission from our Consumer Challenge Panel. Appendix A lists the stakeholders who made submissions to this process.[5] We also held a meeting with interested stakeholders on 11 April to discuss our preliminary F&A.

Table 1 summarises our NSW distribution determination process.

Table 1 New South Wales distribution determination process

Step	Date
AER published preliminary positions F&A for NSW distributors	10 March 2017
AER to publish final F&A for NSW distributors	July 2017
NSW distributors submit regulatory proposals to AER	January 2018
AER publishes Issues paper and holds public forum	March/April 2018*
Submissions on regulatory proposal close	May 2018
AER to publish draft decisions	September 2018
AER to hold a predetermination conference	October 2018
NSW distributors to submit revised regulatory proposals to AER	December 2018
Submissions on revised regulatory proposals and draft decisions close	January 2019*
AER to publish distribution determinations for regulatory control period	April 2019

* 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.

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*, November 2016. See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016.

5 All submissions are available on the AER's website at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2019-24/aer-position.

This overview sets out our positions 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, operating expenditure and demand management
- expenditure forecasting tools to test the network businesses' regulatory proposals
- how we will calculate depreciation of the network businesses' regulatory asset bases
- how we will price transmission assets (dual function assets).

We summarise below our approach to each of the above matters. Further details of our approach to each matter are set out in the following chapters.

Classification of distribution services

We regulate most distribution services provided by the NSW distributors subject to the NEL and NER. Service classification determines what and how services will be regulated. We will regulate services provided on a monopoly basis under a price or revenue cap, which directly controls the charges that a distributor may levy a customer. Less prescriptive regulation is applied 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,[6] following the introduction of our Ring-Fencing Guideline.[7] Broadly, 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 separate to the regulated network business, unless it applies for, and receives, a waiver under the ring-fencing guideline.

Table 12 provides an overview of the different classes of distribution services for the purposes of economic regulation under the NER.

6 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*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016.

7 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

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 may be earned 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 prices for these services.
Non-distribution services		Services that are not distribution services.[8]	We have no role in regulating these services.

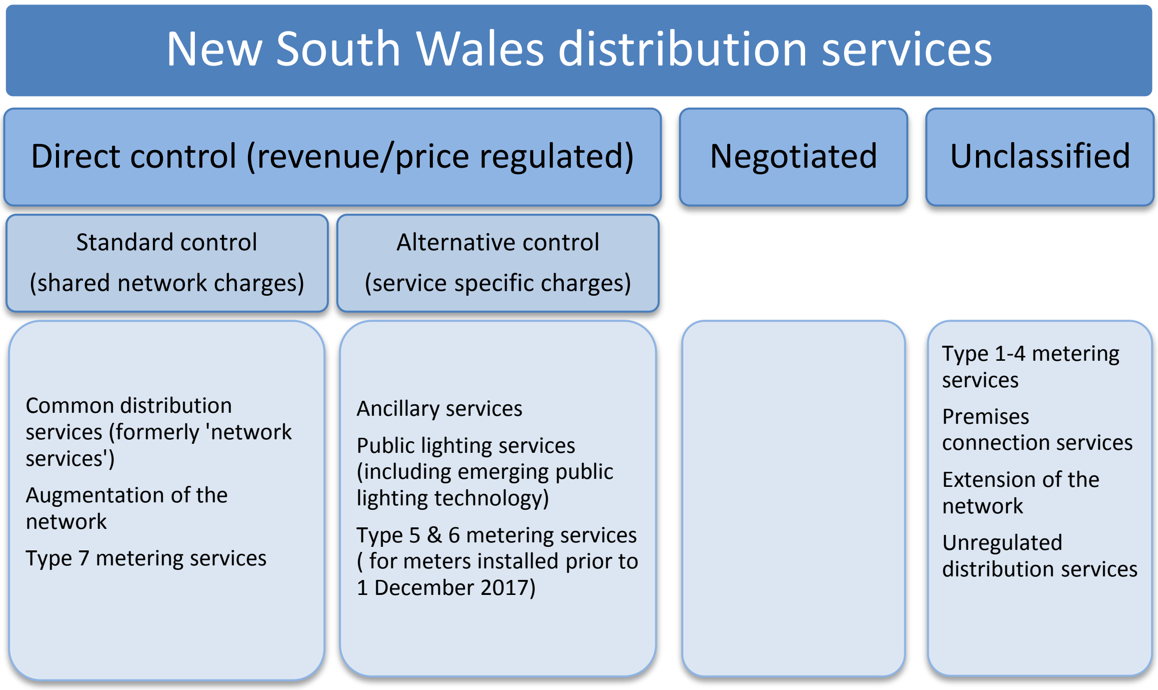
Source: AER

Our proposed position is to change the classification of some NSW distribution services for the 2019−24 regulatory control period. While we propose to retain the existing service classifications for most services, we intend 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 new distribution services might be classified.

Our proposed service classifications for the NSW network businesses are set out in figure 1 below.

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

Figure 1 AER proposed classification of NSW distribution services



Source: AER

Our final F&A decision on service classification is not binding for our determination on the NSW network businesses' regulatory proposals. However, under the NER we may only change our classification approach if unforeseen circumstances arise, justifying a departure from our final F&A position.[9]

Control mechanisms

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.[10] We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A.[11] In deciding control mechanism forms, we must select one or more from those listed in the NER.[12] These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

Our decision on the form of control mechanisms for the NSW network businesses are:

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

9 NER, cl. 6.12.3(b).
10 NER, cl. 6.2.5(a).
11 NER, cl. 6.12.3(c).
12 NER, cl. 6.2.5(b).

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.[13]

Our final F&A decision on the form of control is binding on us and the NSW distributors for the 2019−24 regulatory determination.[14] We may only vary our proposed control mechanism formulas in response to unforeseen circumstances.[15]

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 available incentive schemes to each of the NSW network businesses:

- 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 the NSW network businesses.

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline[16] 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 the NSW network businesses in the 2019−24 regulatory control period.

Our expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the NSW distributors' regulatory proposals. We intend to apply the assessment/analytical tools set out in the guideline and any other appropriate tools for assessing expenditure forecasts.

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

13 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.

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

15 NER, cl. 6.12.3(c1).

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

Depreciation

When we roll forward the NSW network businesses' regulatory asset bases (RABs) for the upcoming regulatory control period we must adjust for depreciation. Our proposed approach is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RABs as at 1 July 2024. In combination with our proposed application of the CESS this approach will maintain incentives for the distributors 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.

Under transmission pricing rules the asset costs are recovered from all NSW electricity customers, like the cost of other transmission assets. Distribution pricing rules recover costs from only the customers of a specific distribution network.

Ausgrid and Endeavour Energy operate dual function assets. Essential Energy does not. Our decision is to apply transmission pricing rules to Ausgrid's dual function assets because doing otherwise would significantly impact Ausgrid's customers. We will apply distribution pricing rules to Endeavour Energy's dual function assets because, due to the nature of those assets, applying transmission pricing rules would not change their cost recovery—Endeavour Energy customers would still finance those assets.

Our final F&A decision on dual function assets is binding.[17]

Consumer engagement by network service providers

We released the Consumer Engagement Guideline for Network Service Providers[18] in 2013 to assist network businesses develop, implement, and ultimately entrench stakeholder engagement as part of its business processes.

Our Consumer Challenge Panel (CCP sub-panel 10), in its submission to our preliminary F&A, stressed that there is an expectation that the NSW distributors use 'best endeavours' to apply the Consumer Engagement Guideline as a minimum standard in developing their regulatory proposals for 2019−24.[19] We agree with CCP sub-panel 10's submission on this issue.

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

18 AER, *Consumer engagement guideline for network service providers*, November 2013; AER, *Explanatory statement − Consumer engagement guideline for network service providers*, November 2013, see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/consumer-engagement-guideline-for-network-service-providers.

19 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*,

1 Classification of distribution services

This chapter sets out our proposed approach on the classification of distribution services provided by NSW distributors in the 2019−24 regulatory control period. 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[20]
- 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. We introduced our ring-fencing guideline for electricity distributors and our classification decisions will also settle ring-fencing obligations that will apply to each NSW distributor for the 2019−24 regulatory control period.[21] For these reasons, we have closely reviewed the table of distribution services at appendix C.[22]

We are aware the Australian Energy Market Commission (AEMC) is currently assessing rule change proposals from the Council of Australian Governments Energy Council and Australian Energy Council on contestability of energy services.[23] As the AEMC's consideration of these rule change requests is ongoing, we have developed our proposed classification positions within the current regulatory framework. We aim to provide improved clarity, consistency across jurisdictions as far as practicable, predictability in how new distribution services might be classified and service descriptions that better align with the services being provided.[24] Origin Energy and Endeavour Energy supported our approach to rationalising service classification and service descriptions for consistency across jurisdictions where practicable.[25]

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21 April 2017, p. 23.

20 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.

21 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

22 As requested by Endeavour Energy in its letter to the AER: *Request to update F&A paper for the next regulatory control period*, 25 October 2016, p. 3.

23 AEMC, *Consultation paper, National Electricity Amendment (Contestability of energy services) Rule 2016 (COAG), National Electricity Amendment (Contestability of energy services - demand response and network support) Rule 2016 (Australian Energy Council)*, 15 December 2016.

24 As requested by Essential Energy in its letter to the AER *re: Update to framework and approach paper for the 2019−24 regulatory control period*, 25 October 2016, p. 1; Ausgrid's letter to the AER re: *request to replace F&A paper*, 25 October 2016, p. 2.

25 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1;

Origin Energy submitted that we should incorporate the AEMC's rule change into our classification decisions for 2019−24.[26] We agree with Origin Energy on this issue. The AEMC's draft rule change is not expected to be released until after this F&A is published. However we will take account of the rule change and consider its impact on our service classification decisions as part of the NSW distribution determination process, as appropriate.

1.1 AER's proposed position

Overall, our proposed position is to change the classification of some NSW distribution services for the 2019−24 regulatory control period.

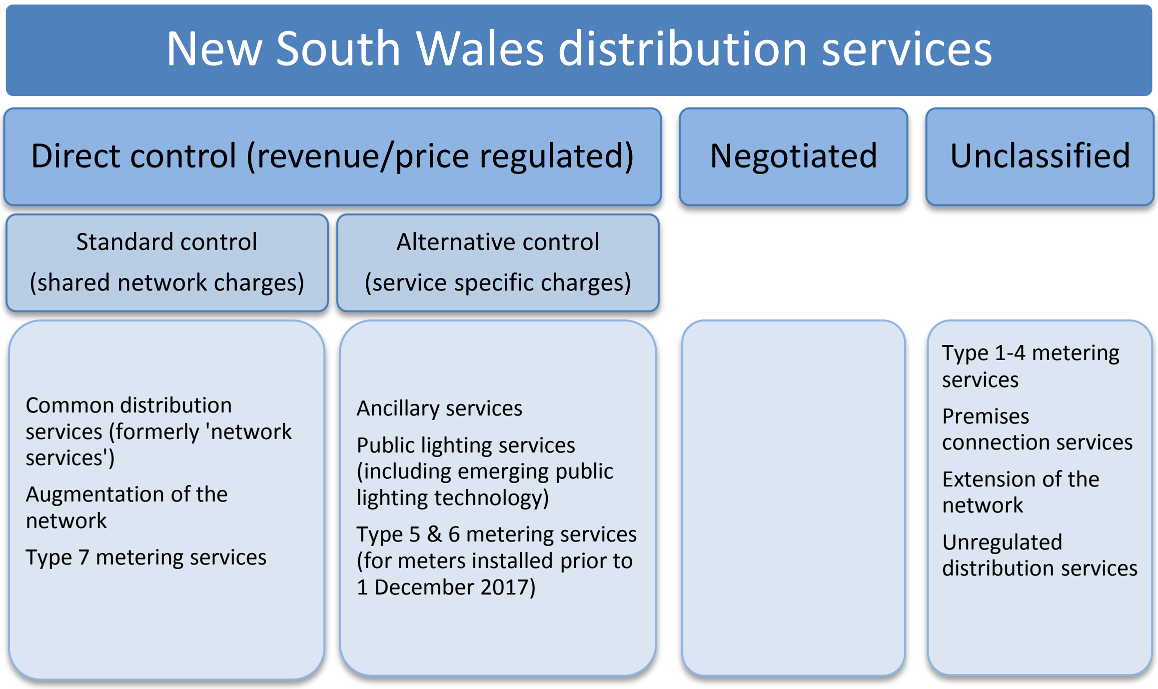
Our proposed position is to group distribution services provided by the NSW distributors as:

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

Figure 1.1 summarises our proposed classification of NSW distribution services. Our assessment approach and reasons follow.

26 Endeavour Energy, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1. Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1.

Figure 1.1 AER proposed approach to classification of NSW 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 – we can only decide on service classification if we understand what the service being provided is. That is, distribution service classification involves the classification of services distributors supply to customers rather than the classification of:
  - the assets used to provide such services
  - the inputs/delivery methods distributors use to provide such services to
  - customers
  - services that consumers or other parties provide to distributors.
- classify distribution services in groups[27] – 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

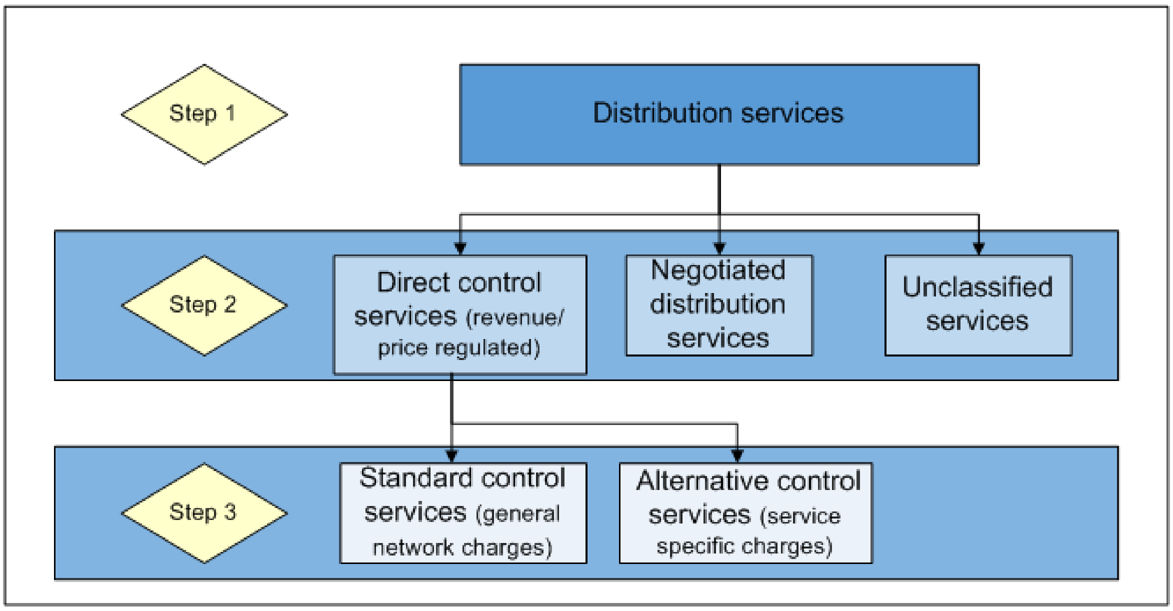
27 NER, cl. 6.2.1(b).

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.

- 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



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.[28] A distribution system is a 'distribution network, together with the

28 NER, chapter 10, glossary.

connection assets associated with the distribution network, which is connected to another transmission or distribution system'.[29]

- 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.[30] We have reproduced these at appendix B. 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 previous form of regulation applied to services and the desirability of consistency in the form of regulation for similar services both within and beyond the jurisdiction.[31]

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.[32] 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.

The NER also specifies that for a service regulated previously, unless a different classification is clearly more appropriate, we must:[33]

- not depart from a previous classification (if the services have been previously classified), and
- if there has been no previous classification—the classification should be consistent with the previously applicable regulatory approach.[34]

Our classification decisions determine how distributors will recover the cost of providing services.[35] 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 who requests 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

29 NER, chapter 10, glossary.
30 NER, cl. 6.2.1(c); NEL, s. 2F.
31 NER, cl. 6.2.1(c).
32 NER, cl. 6.2.2(c).
33 NER, cl. 6.2.2(d).
34 NER, cll. 6.2.1(d) and 6.2.2(d).
35 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).

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:

- 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:

- 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.[36]

1.3 Reasons for AER's proposed position

This section sets out our proposed service classification and reasons for the NSW distributors' 2019−24 regulatory control period for:

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

36 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

- unregulated distribution services.

Appendix C contains a detailed table of our proposed classification of NSW distribution services.

1.3.1 Common distribution services

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 services'.

Common distribution services are concerned with providing a safe and reliable electricity supply to customers.[37] Common distribution services 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 services on a regular basis. Providing common distribution services 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 common distribution services, this service group reflects the provision of access to the shared network to customers.

CCP sub-panel 10 agreed with our preliminary definition and classification of common distribution services, but suggested that the group could be named 'core distribution services' as it refers to the ‘core business’ of a network distribution service provider.[38] Our proposed approach is to retain 'common distribution services' as it has clearer meaning to customers by referring to the common services they receive from the distributors.

Origin Energy submitted that our preliminary description of common definition services[39] lacked clarity regarding what activities are or are not covered.[40] Essential Energy proposed a more generic description than our preliminary description,[41] while Ausgrid proposed a revised description that we consider is clearer and more comprehensive than our preliminary description.[42] Endeavour Energy supported Ausgrid's proposed description of common distribution services.[43] Having considered the submissions, we have ultimately adopted Ausgrid's proposed description because it provides the clearest description. That description is contained in appendix B. Ausgrid explained in its submission that its common distribution services description contained three key parts.[44] In short, Ausgrid submitted these are:

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37 NER, Chapter 10 glossary.

38 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 7.

39 Set out AER, *Preliminary framework and approach for NSW DNSPs, Appendix B*, March 2017, p. 86.

40 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 1−2.

41 Essential Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 8.

42 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 3−5.

43 Endeavour Energy, *Attachment - Suggested amendments to service classification*, 21 April 2017, p. 1.

44 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 4−5.

1. An overarching description of the services which is based on the definition of 'distribution use of system service' in chapter 10 of the NER. This provides a legally sound footing on which to base the description which is consistent with regulatory obligations as a distributor.

2. A list of the key inputs that are directly or indirectly involved in providing common distribution services. The description only includes the core set of activities which fall into the service group. The exceptions are those activities that fall within common distribution services, but which may not readily appear to do so. For example, activities involved in the relocation of assets forming part of the distribution network but which are not relocations requested by a third party, works to fix damage to the network (including emergency recoverable works) and network demand management for distributor purposes. The phrase 'for distributor purposes' is intended to avoid the capture of unregulated battery storage or micro-grid businesses which provide services that are not distribution services.

3. An express exclusion of any other services that are separately classified but which may still meet the description of common distribution services. The purpose of the exclusion is to ensure that distribution services that are unclassified and therefore unregulated are not inadvertently captured by common distribution services. This is important to facilitate compliance with the ring-fencing guideline.

Ausgrid submitted that the substance of its amended description varies little from our preliminary F&A description, but provides better accuracy and less ambiguity.[45]

Our proposed position is to classify common distribution services as direct control services. Each of the NSW distributors holds an electricity distribution licence which is the only distribution license in place for their respective geographic areas.[46] Under section 17 of the *Electricity Supply Industry Act* (NSW) 1995, a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so. These arrangements create a regulatory barrier, preventing third parties from providing common distribution services.[47] Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of common distribution services.

We must further classify direct control services as either standard or alternative control services.[48] Our proposed position is to retain the current standard control classification for common distribution services. There is no potential to develop competition in the market for common distribution services because of the barriers outlined above.[49] There would be no material effect on administrative costs for us, the NSW distributors, users or potential users

45 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 4−5.
46 Licences are issued by Independent Pricing and Regulatory Tribunal of NSW.
47 NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).
48 NER, cl. 6.2.2(a).
49 NER, cl. 6.2.2(c)(1).

by continuing this classification.[50] We currently classify common distribution services (or 'network services') in NSW and all other NEM jurisdictions as standard control services.[51] Further, distributors provide common distribution services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[52]

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. However, we currently do not classify this service, treating it as an unregulated distribution service. This is because the cost of these works may be recovered through other avenues (e.g. under common law). That is, the distributor can seek payment of their costs to fix the network from the parties responsible for causing the damage, through the courts if necessary. However, following the introduction of our ring-fencing guideline, classifying this service as an unregulated distribution service would require it to be ring-fenced. That is, the benefits from not classifying this service are outweighed by the likely costs of having to establish ring-fencing arrangements (staff and office separation) for the provision of this service.

Therefore, our proposed position is for emergency recoverable works to be subsumed into the common distribution services group and classified as a direct control and standard control service. Ausgrid, Endeavour Energy, Essential Energy and CCP sub-panel 10 supported this approach.[53] Distributors are required to 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 against the efficient operating expenditure (opex) incurred by a distributor in performing emergency recoverable works.[54] Ausgrid and Essential Energy supported this approach.[55] This prevents distributors from recovering the cost of emergency repairs twice—as a standard control charge across

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

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

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

53 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 5−6; Endeavour Energy, *Attachment - Suggested amendments to service classification*, 21 April 2017, p. 1; Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 4 and 7.

54 In our preliminary F&A (at p. 21), we incorrectly stated that the cost of emergency repairs recovered from a third party would be netted off the regulatory asset base and treated like a capital contribution. We have changed our position because our preliminary approach may not have achieved the objective of avoiding over-recovery of costs.

55 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 5−6; Essential Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1.

the broader customer base and from the responsible third party. Going forward, we intend to propose this approach in all NEM jurisdictions.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.[56] On 26 November 2015, the AEMC made a final rule that will open up competition in metering services and give consumers more opportunities to access a wider range of metering services.[57]

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.[58]

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.[59]

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[60] and an ability for consumers to opt out of having an advanced meter installed if they have an existing, working meter.[61]

The new arrangements will commence on 1 December 2017 and have required changes to the NER and the National Electricity Retail Rules (NERR).[62] Consequently, our proposed classification of some metering services will also change for the 2019−24 regulatory control period.

Cotton Australia and NSW Irrigators' Council (NSWIC) submitted that the smart meter roll out on an 'as needs' basis will confuse consumers, particularly as to whether its members will need to provide ongoing property access for meter reading.[63] Cotton Australia and NSWIC are calling for significant consumer education and communication. We note the

56 All connections to the network must have a metering installation (NER, cl. 7.3.1A(a)).
57 AEMC, *Competition in metering services information sheet*, 26 November 2015.
58 AEMC, *Competition in metering services information sheet*, 26 November 2015.
59 AEMC, *Competition in metering services information sheet*, 26 November 2015.
60 AEMC, *Competition in metering services information sheet*, 26 November 2015.
61 AEMC, *Final rule to increase consumers' access to new services information sheet*, 26 November 2015.
62 AEMC, *Competition in metering services information sheet*, 26 November 2015.
63 Cotton Australia and NSW Irrigators' Council, *Submission on AER's preliminary framework and approach for Essential Energy*, 21 April 2017, p. 1.

concerns of Cotton Australia and NSWIC. The basis on which meters are provided to customers is a matter that has been considered by the AEMC.[64]

Type 1 to 4 metering services

Type 1 to 4 meters which provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. Type 1 to 4 meters are competitively available[65] and we do not currently regulate them in NSW or in most other jurisdictions—they are not classified and therefore are unregulated distribution services and our proposed position is for them to remain so.

Type 5 and 6 metering services

The NSW distributors are currently the monopoly providers of type 5 (interval) and 6 (accumulation) meters. However, from 1 December 2017 (and therefore before the commencement of the next regulatory control period on 1 July 2019), metering services across the National Energy Market (NEM) will become contestable. Therefore, from 1 December 2017, households and other small customers who traditionally use these meter types may wish to change their metering provider and the type of meter they have. Further, the NSW distributors (or any metering provider)[66] will no longer be permitted to install or replace existing meters with type 5 or 6 meters. As a result, our proposed position is to not classify these services for the 2019−24 regulatory control period.

While the NSW distributors cannot install new type 5 and 6 meters from 1 December 2017, they will continue to operate and maintain existing type 5 and 6 meters until they are replaced. Therefore, the NSW distributors will still recover the capital cost of 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 determination for 2015−19 regulatory control period[67] to promote customer choice and remove any classification barriers limiting contestable provision of these meters.[68] This approach aligned with AEMC's Power of Choice recommendations to unbundle metering costs from shared network charges.[69]

64 AEMC, *Rule Determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 and National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, which discusses market-led roll out. See: http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

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

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

67 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy 2015−19 regulatory control period, Attachment 13 Classification of services*, April 2015, pp. 13−11 to 13−15.

68 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy 2015−19 regulatory control period, Attachment 13 Classification of services*, April 2015, pp. 13−11 to 13−15.

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

Origin Energy submitted that it supported our decision to unbundle type 5 and 6 metering services to facilitate competition, but that we should revisit the annual metering charge applied to customers with type 5 or 6 meters installed prior to 1 December 2017 as our decision to apply this charge was made within a short timeframe.[70]

The AEMC published its draft rule on 26 March 2015. It provided that we should determine 'the arrangements for a distributor to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.[71]

The key issue in the lead up to metering competition was how to recover the capital costs of meters that become stranded when a customer switches to an alternative metering provider. Rather than a large upfront exit fee to recoup the value of the depreciated displaced meter which would create a regulatory barrier to competitive entry, our final decision was that switching customers continue to pay the capital cost component of the regulated annual metering service charge. This approach was introduced in the last NSW reset.[72] Origin Energy submitted that our approach will have a material impact on the uptake of competitively available meters.[73] However, we consider that irrespective of the approach, the residual value of the displaced meters would have to be recovered.

Cotton Australia and the NSW Irrigators' Council submitted that there is still a lack of clarity around the recovery of type 5 or 6 metering capital costs where a customer transitions to a smart meter.[74] To be clear, the annual capital charge we approved in our 2015−2019 determination allows distributors to recover the value of type 5 and 6 meters from all customers with existing connections on their premises, whether or not they subsequently switch from their existing regulated meter to an advanced meter.[75]

While these metering issues are not directly relevant to the F&A, we note that some aspects of the approach to metering adopted in the last determination will likely be revisited as part of the next determination given the submissions we have received from stakeholders.

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

70 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2.

71 AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

72 We had commenced consultation on unbundling type 5 and 6 metering services from standard control as early as December 2012 in a discussion paper, and revisited the issue again in our Stage 1 F&A for the NSW distributors and then our draft and final decisions between March 2013 and April 2015. See AER, *Discussion paper, Classification of type 5 to 7 metering services*, December 2012; AER, *Stage 1 framework and approach for NSW distributors*, March 2013; AER, *Draft decision for NSW distributors − Attachments 13 (Service classification) and 16 (Alternative control services),* November 2014; AER, *Final decision for NSW distributors − Attachments 13 (Service classification) and 16 (Alternative control services),* April 2015.

73 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2.

74 Cotton Australia and NSW Irrigators' Council, *Submission on AER's preliminary framework and approach for Essential Energy*, 21 April 2017, p. 2.

75 AER, *Final decision for NSW distributors − Attachment 16 (Alternative control services),* April 2015, pp. 16-29 to 16-33.

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. NSW distributors are the monopoly providers of type 7 metering services in NSW.[76]

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.[77] 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,[78] and also supported by CCP sub-panel 10.[79]

Ancillary services − Metering

The NSW distributors 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.[80]
- 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.[81]
- 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 C.

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

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

78 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy, Attachment 13, Classification of services*, April 2015, p. 13−26.

79 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 9.

80 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.

81 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.

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.[82]

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach is to not classify these services.[83] That is, we propose to treat them as unregulated distribution services. Importantly, we consider that pre-existing type 5 and 6 metering services, as detailed in appendix C, 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, will be appointed as the metering coordinator as at 1 December 2017.[84] 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 metering coordinator performing its current services like type 5 and 6 metering reading, maintenance and testing, we will classify it as an alternative control service. Ausgrid and SA Power Networks supported this approach.[85]

Cotton Australia and NSW Irrigators' Council submission

Cotton Australia and NSWIC also raised concerns regarding the transition to more cost reflective tariffs. While this issue is not relevant to the F&A, we appreciate that Cotton Australia and NSWIC have used this opportunity to raise an issue important to them. Specifically, Cotton Australia and NSWIC again submitted that we consider allowing its members to access 12 months of interval based data prior to moving to cost reflective tariffs amid concerns that energy costs will increase up to 100 per cent with no corresponding change in electricity use.[86]

These issues were considered in our recent tariff structure statement (TSS) decisions,[87] when raised previously by Cotton Australia and NSWIC.[88] While this issue is not relevant to

82 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.

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

84 NER, cl. 11.86.7.

85 Ausgrid, *Submission on AER preliminary framework and approach*, 27 April 2017, pp. 8−12; SA Power Networks, *Submission on AER preliminary framework and approach for NSW, ACT, TAS*, 21 April 2017, pp. 1−-2.

86 Cotton Australia and NSW Irrigators' Council, *Submission on AER's preliminary framework and approach for Essential Energy*, 21 April 2017, pp. 2−3.

87 For example, AER, *Final decision − NSW distribution businesses, Tariff structure statement 2017−19*, 28 February 2017.

88 Cotton Australia and NSWIC, *Response to AER Issues paper - Tariff Structure Statement Proposals NSW Electricity distributors,* 6 May 2016; *Cotton Australia and NSWIC, Submission to Essential Energy Tariff structure statement*, 26

this F&A, we consider Cotton Australia and NSWICs' suggestion has merit and encourage Essential Energy to consider this as part of its 2019−24 regulatory proposal and TSS proposal.

1.3.3 Connection services

Put simply, a connection service refers to the services a distributor or accredited service provider (ASP)[89] 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).

New South Wales, by virtue of the contestability framework contained in the *Electricity Supply Act* 1995 (NSW), permits customers to choose whether a NSW distributor or an ASP will perform certain connection works where the customer is required to fund the connection in full or in part. The ability of customers to choose who will perform the work and negotiate the price in a competitive market means there are only limited circumstances where we regulate connection services in NSW. This, of course, does not prevent the distributors from providing these services, subject to the obligations set out in our ring-fencing guideline.

Table 1.1 lists the definitions of each connection type together with our proposed classification of each type. Our proposed position slightly from 2015−19 regulatory control period[90] and our preliminary position and is supported by the NSW distributors.[91] The addition of item 'D' in premises connections and augmentations were made to align the service classification descriptions with the NSW distributors' connection service policies required under the NER.

October 2016.

89 The ASP scheme is administered by the NSW Department of Trade and Investment.

90 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy distribution determination, Attachment 13 − Classification of services*, April 2015; NER, cll. 6.2.1(c)(3) and (d) and 6.2.2(c)(3) and (4).

91 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1; Endeavour Energy, *Attachment - Suggested amendments to service classification*, 21 April 2017, pp. 5−6; Essential Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1; Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 10.

Table 1.1 AER's classification of connection services in NSW

Connection services - descriptions	Preliminary classification
Premises connections—Includes any additions or upgrades to the connection assets located on the customer's premises which are contestable (Note: excludes all metering services).[92] Premises connection assets can be further described as:	
A. Design and construction of premises connection assets (where these services are provided contestably).	A. Unclassified
B. Part design and construction of connection assets that are not available contestably (generally as a result of safety, reliability or security reasons). Those parts of project works that are performed and funded by the distributor except where C applies.	B. Standard control
C. Part design and construction of connection assets where a customer requests that connection assets are designed and constructed to an increased standard (beyond that required by the distributors' standards and policies), and where those works are designed and constructed by the distributor (as a result of safety, reliability or security reasons).	C. Alternative control
Extensions—An enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a network service provider that is: A. undertaken by a customer. B. undertaken by a customer but partly funded by a NSP (NSP contribution would be classified as a standard control service while the customer funded component of the service would be unclassified.) C. undertaken by a network service provider.	A. Unclassified B. Unclassified/standard control based on financial contribution C. Standard control
Augmentations— A. Any shared network enlargement/enhancement undertaken by a distributor which is not an extension	A. Standard control B.

92 Also referred to as 'premises connection assets' at cl. 5A.A.1 of the NER.

Connection services - descriptions	Preliminary classification
B. Any shared network enlargement/enhancement undertaken by a customer, but partly funded by a NSP (NSP contribution would be classified as a standard control service while the customer funded component of the service would be unclassified)	Unclassified/standard control based on financial contribution
C. Any shared network enlargement/enhancement undertaken by a customer.	C. Unclassified
D. Any shared network enlargement/enhancement undertaken by a distributor where a customer requests that assets are designed and constructed to an increased standard (beyond that required by the distributors' standards and policies).	D. Alternative control

Source: AER analysis

We consider each connection type below.[93]

Premises connections

We consider that premises connections refer to any additions or upgrades to the connection assets located on the customers' premises (but excludes all 'metering services').

New South Wales has a working contestability framework and competitive market to provide premises connections under the *Electricity Supply Act* 1995 (NSW). This means customers can choose their own service provider and negotiate a price for premises connections. For the above reasons, we intend not to classify premises connections in the 2019−24 regulatory control period. We consider that this is appropriate as the service is subject to competition on the open market.[94]

Extensions

Similar to premises connections, NSW has a working contestability framework and competitive market to provide extension services. Customers can choose their own service extension provider. We consider customers' ability to choose balances the economies of scale and scope otherwise available to the NSW distributors.[95] The NSW distributors may reasonably require works to facilitate further connections, however, the costs will be apportioned between the customer seeking the extension and any additional work the distributor elects to undertake. In the event that subsequent customers do connect to the extension, the customer may seek to share its extension cost under a cost sharing scheme (pioneer scheme) operated by the distributor.[96]

93 NER, cll. 6.2.1 and 6.2.2.
94 NER, cl. 6.2.1(d).
95 NEL, s. 2F(b) and (c).
96 NER, chapter 5A and AER, *Connection charge guidelines for electricity retail customers, Under chapter 5A of the National*

For these reasons, only extensions performed by the distributor or where the distributor makes a financial contribution to the extension will be classified as standard control services. In this instance the distributor is extending the shared network to benefit a non-identifiable customer base and the costs will be shared.[97] All other extensions are unregulated distribution services and will not be classified.

Augmentations

Augmentations refer to any shared network enlargement/enhancement undertaken by a distributor, which is not an extension. For example, expansion of the shared network to accommodate increased demand. We acknowledge there may be some circumstances where a customer may be required to contribute to an augmentation in order to connect to the network. Typically, network augmentation is not attributable to a specific customer.

However, we do not wish to preclude the possibility of a customer contributing to augmentation at this point. The NSW distributors will be required to identify these circumstances in their Connection Policies that will form part of their regulatory proposals.[98] Where this circumstance occurs, the service classification does not change. That is, the customer is receiving a service classified as standard control, but there may be a tailored component over and above the standard control service. In some instances, this additional charge (such as a capital contribution or negotiated charge) may be required by the distributor from the customer.[99] The additional charge component does not alter the classification of the service from a standard control service.

The NSW distributors each hold an electricity distribution licence to provide services for their respective distribution areas in NSW. We consider that these NSW licensing arrangements create a regulatory barrier for third parties to perform augmentations.[100] Additionally, the NSW contestability framework which allows ASPs to perform premises connections and extensions competitively, does not apply to augmentation of the shared network. The NSW distributors may engage a third party to perform augmentations. However, we understand that in most instances, the NSW distributors will not permit third parties to perform augmentations because of the potential impact on the safety, security and reliability of the network.

In most cases, if not all, augmentation of the network is a cost shared by all customers. We therefore consider that the NSW distributors possess significant market power in providing augmentations to the shared network. A third party can only perform an augmentation at a distributor's discretion. This creates a monopoly, which requires a stringent regulatory

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Electricity Rules, June 2012, p. 22.

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

98 The NSW distributors are yet to submit their Connection Policies (indeed, they may be some way from being drafted). Consequently, the classifications may be inconsistent with the Connection Policies. We will consider any such adjustments in our final F&A and if necessary, draft determination to avoid any inconsistencies.

99 AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012 and NER, chapter 5A.

100 NEL, s. 2F(a).

approach. Additionally, we have classified connection services in other NEM jurisdictions as direct control services.[101]

We must further classify direct control services as standard or alternative control services.[102] Our proposed approach is to classify augmentations as standard control services. This is consistent with the current regulatory approach because:

- There is no prospect for competition in the market for augmentations. Our classification will not influence the potential for competition. Rather, the absence of competition is due to the NSW distributors performing augmentations to ensure the safe and reliable supply of electricity to network customers. Additionally, the contestability framework does not extend to augmentations.
- There would be no material effect on administrative costs to us, the NSW distributors, users or potential users. This is because classifying augmentations as standard control services involves the whole customer base sharing the cost.
- We currently regulate augmentations in all other NEM jurisdictions as direct and standard control services.
- The distributors provide augmentations to benefit the shared network and cannot directly attribute costs to individual customers.

For these reasons, we consider that it is clearly more appropriate to retain the current standard control service classification for augmentations.[103]

CCP sub-panel 10 raised concerns that the NSW distributors have limited incentive in supplying connection services, particularly augmentation services, in a timely way as connection services are excluded from the STPIS.[104] We note that the NSW Government[105] administers the Service and Installation Rules of New South Wales. The Service and Installation rules are the recognised industry code outlining the requirements of NSW distributors when connecting a customer to the distribution systems of New South Wales. The Service and Installation rules reflect the requirements outlined in the *Electricity Supply Act 1995* and chapter 5A of the NER. The Service and Installation rules set out the minimum standards for providing safe, reliable and efficient connection services to customer premises.[106]

101 NER, cll. 6.2.1(c)(2) and (c)(3).

102 NER, cl. 6.2.2(c),

103 NER, cl. 6.2.2(d).

104 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 10.

105 Through the Division of Resources & Energy, Department of Industry, Skills & Regional Development (DRE). See http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0020/572114/SIR-Nov-2016-Underlined.pdf.

106 NSW Government, *Service and Installation Rules of New South Wales, The electricity industry standard of best practice for customer connection services and installations*, November 2016.

While CCP sub-panel 10 submitted that we should consider the wider application of the definition of service targets going forward,[107] we note that customers are not without a safety net for the provision of connection services by virtue of the Service and Installation rules.

1.3.4 Ancillary services

Ancillary services share the common characteristics of being services provided to individual customers on an 'as needs' basis (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 the NSW distributors' respective distribution networks. Therefore, similar to common distribution services only the relevant distributor may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than the NSW distributors providing ancillary services in their respective distribution area.[108] Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that the NSW distributors possess significant market power in providing ancillary services.[109]

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 the NSW distributors provide these services to specific customers.[110] As such, the cost of each ancillary service is directly attributable to an individual customer.[111] This results in costs that are more transparent for customers.

We adopt this view even though ancillary services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the administrative costs to us, the distributors, users or potential users of the network.[112] This is because classifying ancillary services as alternative control services is consistent with the current approach.

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 distributors to compete as a discrete price for the service is set for each ancillary service.

107 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 18.
108 NEL, s. 2F(a).
109 NEL, s. 2F.
110 NER, cl. 6.2.2(c)(5).
111 NER, cl. 6.2.2(c)(5) − this includes a small number of identifiable customers.
112 NER, cl. 6.2.2(c)(2).

The NSW distributors and CCP sub-panel 10 supported our approach to classifying ancillary services as alternative control.[113] The NSW distributors proposed some minor changes to service descriptions to better reflect the scope of some ancillary services, which are set out in appendix C.[114]

Origin Energy specifically queried[115] the following services proposed in the detailed table of services at appendix C:

- Network tariff change request − Origin Energy submitted that this should be an automated and largely business as usual activity, particularly in relation to mass market customer switches.[116] However we are satisfied that where a customer or retailer requests a network tariff change, this customer is identifiable and as such, should be attributed the cost of any load analysis and processing changes within IT systems. This approach satisfies the service classification framework we are bound by as set out in the NER.[117]
- Distributor arranged outage for purposes of replacing meter − Origin Energy submitted that the fee for a planned interruption to multiple dwelling premises will likely be met by a single customer seeking the meter upgrade and such fee may be prohibitive.[118] There are instances where other customers may be impacted by supply interruptions where the retailer is not able to arrange the interruption. This is because it may impact customers that are not with the same retailer. Similar to above, an identifiable customer should be attributed the cost of this service. Further, distributors are permitted to charge for this service under the National Electricity Retail Rules from 1 December 2017.[119] We are not able to assess the distributors' proposed prices for this service at the F&A stage. We will consider the proposed price within the regulatory framework to determine the efficient costs.
- NMI extinction fee − Origin Energy submitted that this service is a business as usual activity and should be classified as a standard control service.[120] However, this again is a customer requested service which only the distributor can perform (e.g. processing a final bill and IT processing the extinction of NMI data in the market and distributors'' systems). We therefore consider this service falls into the category of monopoly services

113 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 6; Endeavour Energy, *Attachment - Suggested amendments to service classification*, 21 April 2017, pp.1−4; Essential Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1; Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 10.

114 Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 6; Endeavour Energy, *Attachment - Suggested amendments to service classification*, 21 April 2017, pp.1−4; Essential Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 1.

115 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 2−3.

116 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2.

117 Specifically, NER, cl. 6.2.2(c)(5).

118 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 3.

119 Proposed NERR, cl. 91A.

120 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 3.

used by a small number of identifiable customers on a discretionary basis and should be classified as an alternative control service.[121]

- Correction of metering and market billing data − Origin Energy submitted that it customers may be paying for legacy errors and that the service would be better classified as standard control.[122] Similar to above, this service is provided on request, hence our alternative control classification. Further, the service description at appendix C limits the charging of this fee to correcting metering and market billing data 'due to insufficient or incorrect information *received from* retailers or metering providers' (emphasis added). Therefore, the distributors are unable to charge this fee for 'legacy errors' (i.e. pre-1 December 2017 when metering contestability commences).

1.3.5 Public lighting

The NSW distributors operate and maintain the majority of public lighting systems throughout NSW. The distributors provide these services on behalf of local councils and government departments responsible for public lighting in NSW.

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.[123]

We also propose to continue to include emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that the NSW distributors do not provide at the time of our distribution determination. However, emerging public lighting technology may become available during the 2019−24 regulatory control period. We intend to classify public lighting (including emerging public lighting technology) as a direct control service and further, as an alternative control services.

We consider there to be significant barriers preventing third parties from providing public lighting services. While the NSW distributors do not have a legislative monopoly over these services, a monopoly position exists. This is because the NSW distributors own the majority of public lighting assets. That is, other parties would need access to poles and easements for instance to hang their own public lighting assets.[124] However, the NSW distributors own and control much of this supporting infrastructure. Therefore, similar to common distribution services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the NSW distributors. There is some limited scope for

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

122 Origin Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 3.

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

124 NER, cl. 6.2.1(c)(1), NEL, s. 2F(a), (d).

other parties to provide some public lighting services. For example, other parties may construct new public lights or perform works on independently owned public lighting assets.[125] Apart from these limited exceptions, we consider that a high barrier prevents third parties from entering this market. This limits competition in public lighting and results in the NSW distributors possessing significant market power.[126]

We currently regulate public lighting services in all NEM jurisdictions except the Australian Capital Territory and Northern Territory (where public lighting is separately owned by the respective territory governments). We have classified some public lighting services in South Australia and Victoria as negotiated distribution services and we intend to review this service classification at their next resets. It should be noted the NER does not require us to classify similar services in the same way in each NEM jurisdictions.[127] Unless new information comes to hand, we are not satisfied that the NSW distributors or their customers are adequately equipped to negotiate the provision of public lighting services.

As direct control services, we must further classify public lighting services as either standard or alternative control services.[128] We intend to classify public lighting services as alternative control services 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.[129]
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future— if the NSW Government implements a contestability regime. In the meantime, an alternative control classification supports the NEO by ensuring distributors provide safe and reliable public lighting services to the community.[130]
- there would be no material effect on administrative costs to the AER, NSW distributors, users or potential users. This is because we are retaining the current classification.[131]
- the NSW distributors can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.[132]

During the 2014−19 NSW distribution determination process we received numerous submissions[133] requesting that all public lighting services remain alternative control services.

125 That is, assets, like poles, not owned by the NSW distributors. NEL, s. 2F(f).
126 NEL, s. 2F(d).
127 NER, cll. 6.2.1(c)(3) and 6.2.2(c)(3) and (4).
128 NER, cl. 6.2.2(c).
129 NER, cl. 6.2.2(c)(1).
130 NER, cl. 6.2.2(c)(1).
131 NER, cl. 6.2.2(c)(2).
132 NER, cl. 6.2.2(c)(5).
133 NSW DNSPs, *Response to the AER's preliminary framework and approach paper*, 17 August 2012, pp. 3; REROC,

It was clear from a number of submissions that many NSW public lighting customers thought they did not possess sufficient negotiating power and that the distributors did not devote sufficient time to their public lighting interests.[134] Submissions to our preliminary F&A from Western Sydney Regional Organisation of Councils (WSROC), Southern Sydney Regional Organisation of Councils (SSROC) and Central NSW Organisation of Councils (Centroc) indicated that the situation has not changed and there has been very limited growth in competition for the provision of public lighting services.[135] .

We understand that the NSW Public Lighting Code provides some guidance on the relationship between NSW distributors and customers. However, this code is non-binding.[136] For these reasons, we consider that customers do not have adequate countervailing market power.[137] We are aware that the NSW Government is working with stakeholders to develop a revised Code. CCP sub-panel 10 submitted that we should assist in negotiations to improve consistency of performance standards.[138]

Centroc submitted that we should urge the NSW Government to finalise the revised Code before prices are set for public lighting services.[139] Similarly, SSROC and WSROC submitted that we should liaise with the NSW Government regarding a Code that sets clearly defined service levels before setting prices.[140]

We are supportive of the NSW Government taking an active role in public lighting and facilitating the development of a possibly binding Public Lighting Code to address service standards. However, the development of a binding Code is a matter for the NSW Government and we will monitor how this process develops in the lead up to the next regulatory determination.

Given the background outlined above and support from the NSW distributors and most stakeholders, we intend to retain an alternative control classification for public lighting

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Submission on the AER framework and approach paper, August 2012, p. 5; Gosford City Council, *Submission on the AER framework and approach paper*, 23 August 2012, p. 1; SSROC, *Submission on the AER framework and approach paper*, 24 August 2012, p. 1; Bankstown City Council, *Submission on the AER framework and approach paper*, 28 August 2012, p 1.

134 For example, *Bankstown City Council, Submission on the AER's preliminary positions F&A paper*, 28 August 2012, p. 2; SSROC, *Submission on the AER's preliminary positions F&A paper*, 24 August 2012, p. 5; REROC, *Submission on the AER's preliminary positions F&A paper*, August 2012, p. 5.

135 WSROC, *Submission on AER's preliminary framework and approach for NSW distributors*, 21 April 2017, p. 1; SSROC, *Submission on AER's preliminary framework and approach for NSW distributors*, 12 April 2017, p. 2; Centroc, *Submission on AER's preliminary framework and approach for NSW distributors*, 18 April 2017, p. 1.

136 Department of Energy, Utilities and Sustainability, *NSW public lighting code*, 1 January 2006. The NSW Department of Industry and Investment issued a discussion paper in December 2009 titled *'NSW Public Lighting Code Review'*. This department also published *'NSW Public Lighting Code 2011, Explanatory Paper'* in early 2011, stating that a final Code would be presented to the Minister in April 2011 (p. i). It does not appear that a final Code has been released.

137 NEL, s. 2F (d).

138 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 11.

139 Centroc, *Submission on AER's preliminary framework and approach for NSW distributors*, 18 April 2017, p. 1.

140 WSROC, *Submission on AER's preliminary framework and approach for NSW distributors*, 21 April 2017, p. 1; SSROC, *Submission on AER's preliminary framework and approach for NSW distributors*, 12 April 2017, p. 2.

services in NSW. This reflects the significant role played by a distributor in providing public lighting services and the lack of alternative service providers. We note that the CCP sub-panel 10 submitted that public lighting in greenfield developments should be classified as negotiated distribution services.[141] However, we consider that once a developer or council chooses to have distributor provided (or maintained) public lights, then we should continue to directly regulate the prices of these services. In the event that a distributor is not chosen to provide these services, we do not regulate public lighting services provided or maintained by a third party.

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 at the time of this F&A or are new services identified within a regulatory control period.[142] 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 November 2016, we released the Ring-Fencing Guideline for Electricity Distribution.[143] Our ring-fencing guideline interacts with a number of regulatory instruments, including our service classification decisions. Specifically, our service classification decisions set ring-fencing obligations for each distributor for its next regulatory control period.[144] 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 final 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.[145]

141 Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 11. A greenfield development refers to construction on land where this is no existing buildings or infrastructure. We consider there are two approaches to greenfield developments.

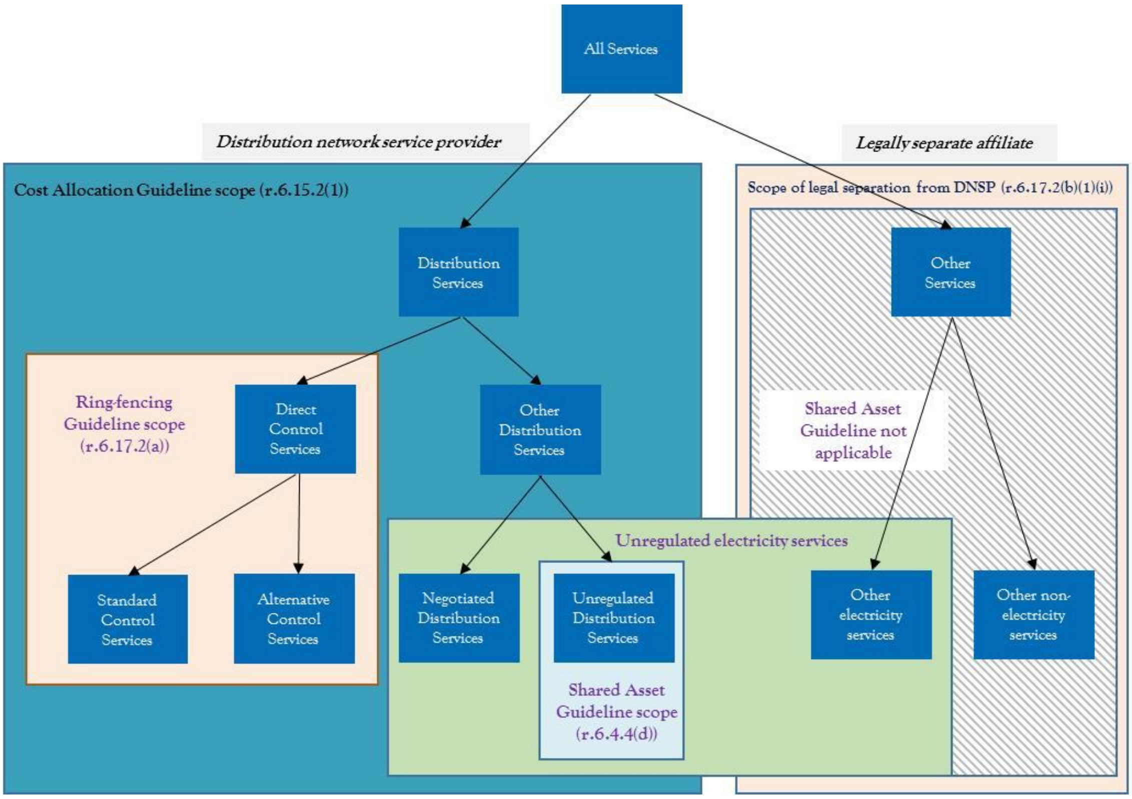
142 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

143 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016. CCP sub-panel 10 submitted that it supported the objectives of the ring-fencing guideline. See: Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 12.

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

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

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).

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.

We expect that there may be a number of distribution services that distributors identify subsequent to this F&A process or within the 2019−24 regulatory control period that would be unregulated. These unregulated distribution services must comply with the ring-fencing guideline until such time as we reconsider service classification for the 2024−29 regulatory control period.

Submission from Red Energy and Lumo Energy

Red Energy and Lumo Energy stated that they are concerned with the lack of clarity in the NER regarding the treatment of shared assets, cost allocation methodology and interaction with our ring-fencing guideline. Red Energy and Lumo Energy submitted that this ambiguity has the potential to threaten competition in emerging contestable energy services located behind the meter.[146] Further, Red Energy and Lumo Energy submitted that we must refrain from approving any distributor requested capital expenditure for configuring batteries located behind the meter that is rolled into the regulatory asset base and provides network support to itself while the distributor simultaneously leases those batteries to a ring-fenced affiliate at a discount.[147] In short, Red Energy and Lumo Energy seek stronger linkages and transparency between service classification and our ring-fencing, cost allocation and shared assets guidelines. These issues are not directly relevant to service classification and the F&A. However, we are cognisant of the importance of these issues and the need for a robust and rigorous enforcement of the ring-fencing guideline and other related guidelines as part of our work program generally.

146 Red Energy and Lumo Energy, *Submission on preliminary framework and approach for NSW*, 21 April 2017, p. 1.

147 Red Energy and Lumo Energy, *Submission on preliminary framework and approach for NSW*, 21 April 2017, p. 3.

2 Control mechanisms

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.[148] This section sets out our decisions, together with our reasons, on the control mechanisms to apply to NSW distributors' direct control services for the 2019–24 regulatory control period. This section also sets out our proposed positions 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 C provides our proposed classification of the NSW distributors' distribution services.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.[149] 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 unforeseen circumstances justify departing from the formulae set out in that paper.[150]

This final F&A paper does not address the form of control mechanism for Ausgrid's dual function assets which will be treated as prescribed transmission services.[151] The NER requires prescribed transmission service revenues to be subject to a revenue cap form of control.[152] The revenue cap formula for these services will be determined as part of our distribution determination. Our decisions on dual function assets are discussed in chapter 6.

2.1 AER's decision

Our decision is to apply the following forms of control in the 2019–24 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, we note all the NSW distributors' proposed the continuation of a revenue cap control mechanism over the 2019–24 regulatory control period.[153] However,

148 NER, cl. 6.2.5(a).
149 NER, cl. 6.12.3(c).
150 NER, cl. 6.12.3(c1).
151 NER, cll. 6.25(c)(ii), NER, cl. 6A.10.1A(b).
152 NER, cl. 6A.3.1.
153 Ausgrid, *Ausgrid's letter regarding framework and approach paper and dual function assets for 2019-24 determination*, 25 October 2016, p. 2; Endeavour Energy, *Request to AER to update the framework and approach for the next regulatory control period*, 25 October 2016, attachment A, pp. 1–2; and Essential Energy, *Essential Energy's framework and approach submission*, 25 October 2016, p. 1.

the NSW distributors' proposed some amendments to the revenue cap formulae to align the formulae with more recent AER decisions. We consider our proposed formula as set out in Figure 2.1 adequately addresses the NSW distributors' considerations.

For alternative control services, the NSW distributors' proposed the continuation of the price caps over the 2019–24 regulatory control period.[154] However, Ausgrid proposed an amendment to the current price cap formulae to include an adjustment factor for recovery of any approved pass through amounts.[155] We have accepted this proposal because it is consistent with the prescribed pass through event definitions set out in the NER, which reference direct control services.[156]

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[157]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.[158]

The NER sets out the form of control mechanisms that may apply to both standard and alternative control services:[159]

- 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)[160]

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)

154 Ausgrid, *Request to replace Framework and Approach paper*, October 2016, p. 5; Endeavour Energy, *Request to AER to update the framework and approach for the next regulatory control period*, 25 October 2016, attachment A, p. 1; and Essential Energy, ***Essential Energy's framework and approach submission***, 25 October 2016, p. 1.

155 Ausgrid, *Request to replace Framework and Approach paper*, October 2016, p. 5;

156 NER, cl. 6.6.1.

157 NER, cl. 6.2.5(b).

158 NER, cl. 6.2.6(a).

159 NER, cl. 6.2.5(b).

160 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.

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.

- 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 decisions on the control mechanisms for the NSW distributors' 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 also considered a price cap control mechanism, which was proposed by AGL.[161]

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.

161 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016.

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.[162] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[163]

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.[164]

Our decision on the control mechanisms for the NSW distributors' alternative control services 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.[165]

162 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.

163 NEL, s. 7.

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

165 NER, cl. 6.2.6(a).

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

2.2.2 Alternative control services

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.[166] 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.[167]

Section 2.4 sets out our consideration of each of the above factors in deciding 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 the NSW distributors' standard control services for the 2019–24 regulatory control period. We have made our decision to apply a revenue cap control mechanism having regard to the factors set out under clause 6.2.5(c) of the NER.

166 NER, cl. 6.2.6(b).
167 NER, cl. 6.2.6(c).

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 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.[168] 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.[169] 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.

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

169 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.

- 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.[170] The tariff structure statement should show how a distributor applied the distribution pricing principles[171] 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:[172]

> 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.[173]

In February 2017, we made final decisions on the initial tariff structure statements for ActewAGL and the distributors in Queensland, New South Wales and South Australia. 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.

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

171 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).

172 NER, cl. 6.18.5(a).

173 NER, cl. 6.12.3(k).

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.[174] 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 continuation of a revenue cap control mechanism to the NSW distributors' 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, the NSW distributors or users.

In contrast, additional administrative costs will be incurred by at least the NSW distributors 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 addressing 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.[175] We note maintaining a revenue cap control mechanism for the NSW distributors' 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 having regard to 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.[176] We consider the continuation of a revenue cap control mechanism for the NSW distributors' 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

174 NER, cl. 6.2.5(c)(2).
175 NER, cl. 6.2.5(c)(3).
176 NER, cl. 6.2.5(c)(4).

control services. However, we have decided to apply a revenue cap to ActewAGL's standard control services for the 2019–24 regulatory control period,[177] This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore maintaining the NSW distributors' 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 addressing clause 6.2.5(c)(4) of the NER than an alternative mechanism.

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.[178]

AGL submitted that we review the control on TasNetworks' revenues in light of uncertainty around future network demand and utilisation.[179] AGL posited a price cap control would better align prudent expenditure and cost minimisation with maintaining network utilisation.

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. Therefore, we consider a revenue cap adequately addresses AGL's concerns that the control mechanism should align prudent expenditure and cost minimisation with maintaining network utilisation.

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.[180] A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.[181] We

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

178 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.

179 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

180 For example, see: *AER, Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67; AER,

181 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.

consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[182]

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.[183]

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.

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.[184]

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. As noted by AGL in its submission to TasNetworks' preliminary F&A, under a revenue cap falling demand creates price increases.[185] The reverse happens with increasing demand. 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

182 NEL, s. 7.

183 NEL, s. 7.

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

185 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

over recovery of revenues for the year in between (year t–1).[186] 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.[187] 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.

On balance, when weighing price flexibility and stability along with the other factors we have considered, our decision is to maintain the NSW distributors' 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.[188] 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.

As stated above, AGL submitted that a price cap control mechanism be considered in light of uncertainty around network demand and utilisation.[189] However, we consider a revenue cap provides better signals for distributors to undertake demand side management.

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.[190] We consider this provides a stronger incentive for a distributor to undertake

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

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

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

189 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

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

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 of 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.[191] 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.[192] Below is proposed formula to apply to the NSW distributors' standard control services revenues. We consider that the formula gives effect to the revenue cap.

Figure 2.1 Proposed revenue cap to apply to the NSW distributors' 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.

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implementing the demand side management projects.

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

192 NER, cl. 6.12.3(c1).

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.[193] As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.[194]

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 final F&A paper. If the review is completed in time, the distributors may need to apply the revised STPIS for the 2019–24 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[195] 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

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

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

195 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.

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

We intend to apply caps on the prices of individual services (price caps) in the 2019–24 regulatory control period to all of the NSW distributors' alternative control services.[196] We propose classifying the following services as alternative control services:

- type 5 and 6 metering services (legacy meters)
- public lighting services
- ancillary services.

We note the NSW distributors' alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2019–24 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.[197] 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 (quoted 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 proposed 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.

Our consideration of the relevant factors is set out below.

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196 The Consumer Challenge Panel supported maintaining price caps for alternative control services. Consumer Challenge Panel - Sub Panel CCP4, *Submission*, 10 March 2015

197 NER, cl. 6.2.6(c).

2.4.1 Influence on the potential to develop competition

We consider a departure from the current price cap controls for the NSW distributors alternative control services would not have a significant impact on the potential development 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, the NSW distributors or users. Additional administrative costs will be incurred at least to the NSW distributors 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 proposed position maintains this regulatory consistency as it continues the application of price cap control mechanisms for the NSW distributors' alternative control services.

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is also generally desirable. Our proposed 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 approach to the formulae that gives effect to the control mechanisms for alternative control services.[198] In making a distribution determination, the

[198] NER, cl. 6.8.1(b)(2)(ii).

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.[199]

Below are our proposed price cap formulae which will apply to the NSW distributors' alternative control services.

Figure 2.2 Price cap formula to apply to the NSW distributors' 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[200] 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.

199 NER, cl. 6.12.3(c1).

200 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.

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.

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 Price cap formula to apply to the NSW distributors' 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[201] 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.

201 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.

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

3 Incentive schemes

This chapter sets out our proposed application of a range of incentive schemes to the NSW distributors for the 2019−24 regulatory control period. At a high level, we intend 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 the NSW distributors in the next regulatory control period.

Our distribution STPIS[202] 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[203] experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.[204]

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

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

203 Except where a jurisdictional electricity GSL requirement applies.

204 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.

- 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.

The NSW distributors may propose to vary the application of the STPIS in their respective regulatory proposals.[205] We can accept or reject the proposed variation in our determination. Each year we will calculate the NSW distributors' 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.[206] 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 the NSW distributors. As the 2015−19 regulatory control period was the first time the NSW distributors were subject to this scheme, a lower level of financial risk to the distributors in terms of penalty or reward of ±2.5 per cent through an s-factor adjustment to the allowable revenue was applied. GSLs are provided for through the Independent Pricing and Regulatory Tribunal's (IPART) GSL scheme, so the GSL component of our scheme does not apply.

3.1.1 AER's proposed position

Our proposed position is to continue to apply the national STPIS to the NSW distributors in the 2019−24 regulatory control period. We propose to:

- set revenue at risk for each distributor at ±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[207]
- apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI and customer service (telephone answering) parameters

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

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

207 Currently, only Ausgrid has CBD feeders.

- 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 the NSW distributors remain subject to a jurisdictional GSL scheme.

We are currently undertaking a review of the STPIS. If the review is completed in time, NSW distributors may need to apply the revised STPIS for the 2019–24 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

The Consumer Challenge Panel (CCP10) supported the application of STPIS as proposed in the preliminary F&A. CCP10 also submitted that we should consider for the STPIS a wider application of the definition of service targets and performance in upcoming determinations.[208] As part of our review we will consult on broader definition on service reliability and performance.

Ausgrid sought greater clarity regarding the proportion of revenue placed at risk and network segment according to the feeder categories. Ausgrid is also currently exploring a pilot scheme under the NER on different customer service measures and has proposed amending the telephone answering definition, to exclude days following a major event.[209] We consider any proposed amendment to the current scheme should be considered as part of the current STPIS review.

Essential Energy submitted that more work is needed on developing VCR and that we are well placed to work on a national VCR.[210] We have accepted and applied the VCR values published by AEMO in 2014 for a number of revenue determinations. Should distributors consider that its customers have a different value to supply reliability, it should seek customers' feedback on this matter for our consideration in setting the incentive rates. As identified in IPART's final report,[211] the calculation of VCR is a very complex matter. Any further reviews must be carefully scoped and implemented.

[208] Consumer Challenge Panel Sub Panel CCP10, *Submission to Preliminary framework and approach (F&A) Ausgrid, Endeavour Energy and Essential Energy*, 21 April 2017, pp.17–18.

[209] Ausgrid, *Submission on AER's preliminary framework and approach paper*, 27 April 2017, pp. 115–16.

[210] Essential Energy, *Submission on AER's preliminary framework and approach paper*, 21 April 2017, pp. 3–4.

[211] IPART, "Electricity transmission reliability Standards, An economic assessment" December 2016.

3.1.2 AER's assessment approach

In deciding how to apply the scheme we have considered the requirements of the NER. The NER sets out certain requirements in relation to developing and implementing a STPIS.[212] 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
- 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.[213]

3.1.3 Reasons for AER's proposed position

Our reasons for applying the STPIS to NSW distributors in the next regulatory control period are set out below.

212 NER, cl. 6.6.2(b).

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

Jurisdictional obligations

In NSW, the Independent Pricing and Regulatory Tribunal (IPART) administers and monitors compliance with the distribution licence conditions set by the NSW Department of Trade and Investment. Our proposed approach to applying the STPIS in NSW is to not create duplication or compromise NSW distributors' ability to comply with the jurisdictional requirements. Our proposed approach is therefore to not apply the GSL component of our national STPIS while the GSL arrangements in the NSW remain in place. We will amend this position if the NSW Government advises that these arrangements will cease to apply.

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.[214]

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. [215]

In September 2014 AEMO completed analysis of the VCR across the NEM.[216] 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,[217] 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 the NSW. 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 NSW distributors at ± 5 per cent as we do not consider that a lower level would better meet the objectives of the STPIS. We did not receive any submissions on this issue.

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

215 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.

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

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

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.[218] Our preferred approach is to base performance targets on NSW distributors' average performance over the past five regulatory years.[219] 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.[220] In NSW 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.[221]

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

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

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

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

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.

The NER require us to consider the possible effects of the STPIS on a distributor's incentives to implement non-network alternatives to augmentation.

In the past we have received submissions requesting outages caused by failed non-network solutions be excluded from the STPIS. This is on the basis that the exclusion of these outages will increase the use of non-network solutions. We consider that such arrangement will transfer the financial risk of non-network solution operators to customers.

We consider that non-network solution operators and the distributor are the parties best placed to manage the risk of outages rather than the customers. Further, as customers are the party who finally fund the non-network solutions adopted by the distributors through network charges, they should not become the party to bear the risk of outages of such projects.

The STPIS treats the reliability implications of network and non-network solutions symmetrically, neither encouraging nor discouraging non-network alternatives to augmentation. Hence, we consider the current incentive framework of the STPIS is adequate to encourage distributors to select appropriate network or non-network solutions to manage their networks.

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.

Ausgrid and Essential Energy stated their view on whether the EBSS should apply in the 2019–24 regulatory period will depend on the outcome of the AER's judicial review application.[222] Endeavour Energy recommended we provide analysis supporting the economic rationale underpinning the scheme and clarify the interaction between the EBSS and benchmarking. It considered the EBSS should only be applied in conjunction with forecast opex being set using the revealed cost method.[223]

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

222 Ausgrid, *Request to replace the framework and approach paper*, 25 October 2016, p. 6. Essential Energy*, Request to replace the framework and approach paper*, Attachment A, 25 October 2016, p. 2.

223 Endeavour Energy, *Request to replace the framework and approach paper*, Attachment A, 25 October 2016, p. 6.

3.2.1 AER's proposed position

We intend to apply the EBSS to the NSW distributors in the 2019–24 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between consumers and the distributors.[224] We will decide if and how we will apply it in our determinations. Our determinations will take into account the information available to us at that time as to the distributors' revealed costs and the basis on which we approve their forecast opex.

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.[225] We must also have regard to the following factors in developing and implementing the EBSS:[226]

- 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 proposed position

The EBSS applies to Endeavour Energy in the 2015–19 regulatory control period but it does not currently apply to Ausgrid[227] or Essential Energy.[228]

At the time we made our determinations for the 2015–19 regulatory control period, economic benchmarking and other corroborating evidence indicated that Ausgrid's opex and Essential Energy's opex was higher than opex incurred by a benchmark efficient service provider. In our decisions,[229] we noted that Ausgrid and Essential Energy had just over three years before they submitted their next regulatory proposals. Consequently, it was uncertain whether, and to what extent, we were likely to rely on their revealed costs in the 2015–19 regulatory control period to forecast opex in the 2019–24 regulatory control period. It

224 NER, cl. 6.5.8(a).

225 NER, cl. 6.5.8(a).

226 NER, cl. 6.5.8(c).

227 AER, *Ausgrid distribution determination 2015–19, final decision*, p.9-6.

228 AER, *Essential Energy distribution determination 2015–19, final decision*, p. 9-6.

229 AER, *Ausgrid distribution determination 2015–19, final decision*, April 2015, Attachment 9, p. 9-9. *AER, Essential Energy distribution determination 2015–19, final decision*, April 2015, Attachment 9, p. 9-8.

followed that there was not a strong reason to apply the EBSS in the 2015–19 regulatory control period.

We received several submissions regarding the EBSS.[230] The Consumer Challenge Panel (Sub panel 10) supported the application of the EBSS to the extent that it fairly shared efficiency gains and losses between the business and consumers.[231] Of the distributors, Ausgrid and Essential Energy made submissions questioning the basis upon which we will decide whether to apply the EBSS.

Ausgrid was concerned that our decision to apply the EBSS in the 2019–24 regulatory control period depends on whether we expect to use its revealed costs to forecast opex in the 2024–29 regulatory control period.[232] It stated we cannot now know what method we will use to forecast opex in the 2024–29 regulatory control period that far in advance. Further, if we pre-empt that decision, it considered we will be by-passing the 'propose-respond' model in Chapter 6 of the NER. Consequently, it wishes to engage further with us about the basis on which we will decide whether to apply the scheme. Essential Energy also submitted concerns about applying the EBSS without more certainty around how we would assess forecast opex.[233]

We note the distributors' concerns and provide the following clarification.

The EBSS is intrinsically linked to a distributor's revealed costs. In assessing a distributor's opex proposal, we seek to identify an efficient opex amount in the base year (the 'revealed costs' of the distributor), which we use to develop an alternative estimate of total opex for the 2019−24 regulatory control period. We compare this to a distributor's opex proposal when assessing it against the opex criteria. If we approve opex that reflects a distributor's revealed costs and apply the EBSS, and the distributor then makes an incremental efficiency gain, it will receive a reward through the EBSS. The lower revealed costs will inform our assessment of the distributor's proposed opex forecast for the subsequent period such that consumers are likely to benefit from those lower costs on an ongoing basis. This is how efficiency improvements are shared between consumers and the business.

Where approved forecast opex reflects revealed costs, the application of the EBSS serves two important functions:

1. it removes 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
2. it provides a continuous incentive for a distributor to pursue efficiency improvements across the regulatory control period.

230 Consumer Challenge Panel (sub-panel 10), *Submission on NSW preliminary framework and approach*, 21 April 2017, pp. 5 and 16.

231 Consumer Challenge Panel (sub-panel 10), *Submission on NSW preliminary framework and approach*, 21 April 2017, p. 16.

232 Ausgrid, *Submission on NSW preliminary framework and approach*, 27 April 2017, pp. 16-17.

233 Essential Energy, *Submission on NSW preliminary framework and approach*, 21 April 2017, p. 2.

The EBSS does this by allowing a distributor to retain efficiency gains (or losses) for a total of six years (typically), regardless of the year in which it was made.

We will determine if we will apply the EBSS when we have the distributors' proposals and assess that against their revealed costs. This will inform us as to whether the application of the EBSS will sufficiently benefit electricity consumers in terms of any likely reward or penalty, and if it will provide a continuous incentive to the distributors to pursue efficiency improvements.

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 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.[234] 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.

[234] 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.

3.3.1 AER's proposed position

We intend to apply the CESS, as set out in our capex incentives guideline,[235] to the NSW distributors in each regulatory year of the 2019−24 regulatory control period. Our approach was supported by CCP sub-panel 10 and each of the NSW distributors.[236]

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:[237]

- make that decision in a manner that contributes to the capex incentive objective set out in the NER[238]
- consider the CESS principles,[239] capex objectives,[240] other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

Broadly, 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 proposed position

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

The NSW distributors 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.[241] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[242] 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.

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

236 Consumer Challenge Panel (sub-panel 10), *Submission on NSW preliminary framework and approach*, 21 April 2017, p. 16; Ausgrid, *Submission on NSW preliminary framework and approach*, 27 April 2017, p. 17; Endeavour Energy, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 1 and 5; Essential Energy, *Submission on NSW preliminary framework and approach*, 21 April 2017, p. 2.

237 NER, cl. 6.5.8A(e).

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

239 NER, cl.6.5.8A(c).

240 NER, cl. 6.5.7(a).

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

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

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.[243] 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 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.

Ausgrid considered that the CESS should encourage the deferral of capital where opportunities arise and that generally customers receive lower prices when this occurs. We agree that the CESS should encourage the efficient deferral of capex. [244] However, we support the exclusion of rewards under the CESS in certain circumstances. In particular, CESS rewards should be potentially excluded where a capex underspend arises from the deferral of capex between regulatory control periods, and customers do not receive any benefit from this capex deferral. This issue was discussed as part of the development of the CESS (refer to our explanatory statement dated 29 November 2013).[245]

In addition, Ausgrid stated that it has concerns that our revenue determinations do not specify projects for which Ausgrid receives funding. Ausgrid further stated that we may wish to consider a mechanism to determine the projects which have been deferred as a result of the using a substitute forecast.[246] While Ausgrid has not directly referred to the relevance of

243 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.

244 Ausgrid, *Submission on NSW preliminary framework and approach*, 27 April 2017, p. 17.

245 AER, *Explanatory statement, capital expenditure incentive guideline for electricity network service providers*, November 2013, pp.46-47.

246 Ausgrid, *Submission on NSW preliminary framework and approach*, 27 April 2017, p. 17.

this issue to the CESS, it is important to set out our approach to assessing the ex-ante capex forecasts.

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.

CitiPower Powercor submitted that the calculation of the CESS payment should be performed consistently with the post-tax revenue model allowance calculation. As such, CitiPower Powercor submitted that to ensure an actual 30 per cent sharing is achieved, the model should be modified to accommodate the annually changing nominal rate of return and inflation rate.[247] We will review the method to calculate the revenue effects of the application of the CESS in the current regulatory period as part of the revenue determination.

3.4 Demand management incentive scheme and innovation allowance mechanism

This section sets out our proposed approach and reasons for applying our new demand management incentive scheme (DMIS) and demand management allowance mechanism (Allowance Mechanism) to the NSW distributors in the 2019−24 regulatory control period.

We have applied a demand management incentive scheme (current scheme) to each of the NSW distributors for the current regulatory control period.[248]

Our current scheme consists of two parts. The first is the demand management innovation allowance (DMIA) which is incorporated into the NSW distributors' revenue allowance for each year of the regulatory control period. The NSW distributors prepare an annual report on their expenditure under the DMIA in the previous year, which we then assess against specific criteria.[249] The second element is a forgone revenue component, which allows a

247 CitiPower Powercor, *Submission on AER preliminary framework and approach for NSW distributors*, 21 April 2017, p. 4.
248 NER, version 52, cl. 6.6.3 (a).
249 The DMIA excludes the costs of demand management initiatives approved in our determination for the 2012–17 period.

distributor to recover forgone revenues that are directly attributable to a non-tariff demand management project or program approved under the DMIA. Compensation for foregone revenue is not applied where a distributor is subject to a revenue cap rather than a price cap.

Currently only the DMIA (Part A of the scheme) applies to the NSW distributors as they are subject to a revenue cap form of control. As we will apply a revenue cap form of control to standard control services in the next regulatory control period, compensation for foregone revenue will not be relevant to the NSW distributors.

On 20 August 2015, the AEMC published a rule determination changing the application of the current scheme.[250] There are now two parts of the framework under the NER:

- The DMIS, with the objective to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.
- The Allowance Mechanism, with the objective to provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs.

In contrast, the objective under the current scheme has been to provide incentives for distributors to implement efficient non-network alternatives, or to manage the expected demand for standard control services in some other way, or to efficiently connect embedded generators. The respective objectives of the new DMIS and Allowance Mechanism are therefore different to that under the current scheme.

The DMIS and Allowance Mechanism will not affect the classification of distribution services, the form of the control mechanisms as specified in this F&A paper, the formulas that give effect to those mechanisms or the pricing of services provided by dual function assets.

We are currently developing a new DMIS and Allowance Mechanism. We published a consultation paper in January, facilitated a stakeholder forum in April, and ran a stakeholder videoconference in June.[251] We expect to publish the new DMIS and Allowance Mechanism by late 2017.

3.4.1 AER's proposed position

We are currently developing the new DMIS and Allowance Mechanism consequent to the rule change in August 2015, to apply to the NSW distributors in the 2019−24 regulatory control period. CCP sub-panel 10, Endeavour Energy, Essential Energy and Ausgrid accepted our preliminary position to apply the new DMIS and Allowance Mechanism in the next regulatory control period.[252] Ausgrid also included statements of its preferred DMIS and

250 AEMC, *Rule Determination: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, August 2015.

251 For details on our consultation process, see our demand management project page under: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism .

252 Consumer Challenge Panel (Sub-panel 10), *Submission on preliminary framework and approach for NSW distributors*, 21

Allowance Mechanism framework.[253] We are considering stakeholder preferences as part of the DMIS and Allowance Mechanism consultation process.

3.4.2 AER's assessment approach to the DMIS

The NER require us to take several factors into account in developing and implementing a DMIS for the NSW distributors.[254] These are:

DMIS Objective

- The DMIS should provide the NSW distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.

Benefits to consumers

- The DMIS should reward the NSW distributors for implementing relevant non-network options will deliver net cost savings to electricity consumers.

Balanced incentives

- The DMIS should balance the incentives between expenditure on network options and non-network options relating to demand management.
- The DMIS should take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market associated with implementing relevant non-network options.
- The level of incentive the DMIS provides should be reasonable considering the long term benefit to retail customers.
- The DMIS should not include costs that are recoverable from another source, including under a relevant distribution determination.
- The DMIS should not impose penalties on distributors.
- The length of a regulatory control period should not limit the DMIS's incentives if this would not contribute to achieving the objective of the DMIS.

3.4.3 Reasons for AER's proposed position on DMIS

This section outlines the reasons for our intention to apply the DMIS to the NSW distributors in the 2019–24 regulatory control period.

The usage patterns of geographically dispersed consumers determine how electrical power flows through a distribution network. Since consumers use energy in different ways, different

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April 2017, p. 15; Endeavour Energy, *Response to AER preliminary framework and approach*, 21 April 2017, pp. 1 and 5; Essential Energy, *Submission on AER preliminary framework and approach for NSW distributors*, 21 April 2017, p. 1; Ausgrid, *Submission on preliminary framework and approach*, April 2017, pp. 2, 17−18.

253 Ausgrid, *Submission on preliminary framework and approach*, April 2017, pp. 17−18.

254 NER, cl. 6.6.3(c).

network elements reach maximum utilisation levels at different times. Distributors have historically planned their network investment to provide sufficient capacity for these situations. Peak demand periods are typically brief and infrequent, but network infrastructure is built to operate during these peak periods without service interruptions. Hence, at other times there is significant redundant capacity.

This underutilisation means that augmentation of network capacity may not always be the most efficient means of catering for increasing peak demand. In the context of providing distribution services, demand management refers to any effort by a distributor to modify the drivers of network usage, including reducing peak demand or changing the demand profile.[255] Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

DMIS Objective

The DMIS must incentivise distributors to undertake non-network initiatives relating to demand management. Developing such incentives requires considering the impacts of control mechanisms in providing incentives. It also requires considering how a DMIS will promote cost efficient non-network options that relate to and are likely to achieve demand management outcomes. Our consultation paper discussed a range of mechanisms that could contribute to the achievement of this objective.[256]

Benefits to consumers

Customers ultimately will pay for any demand management incentives. Therefore, the rewards for demand management should target implementing non-network projects that will bring net cost savings to retail customers.[257] The NER recognise that these net cost savings to retail customers could be via the net economic benefits delivered from implementing relevant non-network options.[258] We will design the DMIS so its expected long term benefits exceed the costs to consumers resulting from any associated adjustment to regulated revenues. The NER recognise that the operation of the DMIS may result in benefits that accrue over multiple periods.

Balanced incentives

We intend to assess projects, for which distributors apply for incentives under the DMIS, using criteria that will balance the incentives between expenditure on network options and non-network options relating to demand management. We must also design the DMIS so the costs to consumers resulting from the associated adjustment to regulated revenues do not

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255 For example, agreements between distributors and consumers to switch off loads at certain times or allowing distributors to directly control consumer usage via load control devices reduces the demand for power drawn from the distribution network at peak times.

256 AER, *Consultation Paper- Demand management incentive scheme and innovation allowance mechanism*, January 2017.

257 NER, cl. 6.6.3(c)(2).

258 NER, cl. 6.6.3(c)(3).

exceed its long term expected benefits, including when we take into account the net economic benefits across all participants in the market. In balancing this, we recognise that the operation of the DMIS may result in cost impacts within a regulatory control period where the benefits are unlikely to be revealed until later periods.

The DMIS will encourage demand management initiatives which are likely to provide long term efficiency gains to energy consumers that will outweigh any short term price increases. For instance, these initiatives might reduce the costs of investment in new infrastructure. This might occur through the deferral of, or removal of the need for, network augmentation/expansion or replacement/refurbishment expenditures, such as via a more efficient use of existing infrastructure.

The DMIS will be designed so all costs recovered from other sources will be excluded from its incentive payments. In developing the DMIS, we are having regard to the effect that it could have on the incentives created by the EBSS, CESS and STPIS, and vice versa. We are also avoiding imposing penalties as part of the DMIS.

3.4.4 AER's assessment approach to the Allowance Mechanism

The NER require us to take several factors into account in developing and implementing Allowance Mechanisms for the NSW distributors.[259] These are:

Allowance Mechanism Objective

- The Allowance Mechanism should provide the NSW distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs.

Benefits to consumers

- Projects to which the Allowance Mechanism applies should have the potential to deliver ongoing reductions in demand or peak demand. They should be innovative, and should not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.
- The Allowance Mechanism should provide a reasonable level of the allowance considering the long term benefit to retail customers. It should only provide funding that is not available from any another source, including under a relevant distribution determination.
- The Allowance Mechanism will require distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance.

259 NER, cl. 6.6.3A(c).

3.4.5 Reasons for AER's proposed position on Allowance Mechanism

This section outlines the reasons for to apply the Allowance Mechanism to the NSW distributors in the 2019−24 regulatory control period.

Distributors have historically planned their network investment to provide sufficient capacity for the periods where the network elements reach maximum utilisation levels. Peak demand periods are typically brief and infrequent, but network infrastructure is built to operate during these peak periods without service interruptions. Hence, at other times there is significant redundant capacity. Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation and reducing long term network costs.

Research and development demand management projects will drive innovation in non-network solutions and have the potential to reduce long term network costs.

Allowance Mechanism Objective

The Allowance Mechanism objective is to provide funding for research and development in demand management projects that have the potential to reduce long term network costs.

We will consider methods to encourage the selection of research and development projects which have the potential to reduce long term network costs via demand management methods.

Benefits to consumers

The Allowance Mechanism design will aim to fund demand management with the potential to reduce long term network costs. It will fund projects that are innovative and would not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal. We should be willing to remove funding ex-post for projects that fall short of this principle.

We consider there will be merit in clarifying the definition of innovative projects and of non-network projects, and for the development of criteria for assessment of projects as part of the designing of the Allowance Mechanism. For example, clarification of innovative tariff trials may be required.

The Allowance Mechanism will be designed so only funding is supplied which is not available from any another source, including under a relevant distribution determination and this will form an assessment criteria for projects.

The design of the Allowance Mechanism will require distributors to publish reports on the nature and results of demand management projects that receive the allowance. Publication of such reports enables the knowledge gained these projects to be leveraged by other industry participants, with potentially greater consumer benefits.

4 Expenditure forecast assessment guideline

This chapter sets out our intention to apply our expenditure forecast assessment guideline (the EFA guideline)[260] including the information requirements applicable to NSW electricity distribution network service providers for the 2019−24 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 require NSW electricity distributors to advise us by 30 June 2017 of the methodology they propose to use to prepare their forecasts.[261] In the final F&A we must advise whether we will deviate from the EFA guideline.[262] This will provide clarity on how we will apply the EFA guideline and the information the NSW electricity distributors should include in their regulatory proposals. This contributes to an open and transparent process and makes our assessment of expenditure forecasts more predictable.[263]

The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of the expenditure forecasts 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.[264]

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

260 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.

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

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

263 As per NER, cl. 6.8.2(c2) each of the NSW distributors are required to submit expenditure assessment information in their regulatory proposal. The NSW distributors' responses to Reset Regulatory Information Notice pertaining to the forecast data will satisfy the information requirements contained in the AER's Expenditure Forecast Assessment Guideline as set out in this F&A.

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

we may employ a range of different estimating techniques to assess an expenditure forecast.

We received six submissions on our approach to implement the EFA guideline as set out in our preliminary F&A.[265] While most submissions supported our intention to apply the EFA guideline, they raised concerns about our benchmarking approach, similar to the concerns NSW distributors raised previously.[266]

CitiPower Powercor, SA Power Networks, Essential Energy and Endeavour Energy all considered we should commence an open and transparent consultation process to review our benchmarking approach following the Full Federal Court appeal outcome. The Full Federal Court handed down its decision 24 May 2017.[267] We are carefully considering this decision.

We will continue to develop and use economic benchmarking to inform our expenditure decisions. Economic benchmarking remains a tool in assessing the relative efficiency of network services providers. It 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.

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265 Endeavour Energy, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 5; Essential Energy, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 3; Citipower/Powercor, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2–5; Consumer Challenge Panel 10, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 19–20; SA Power Networks, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2–3; Ausgrid, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 19–20.

266 Ausgrid reserved its right not to form a view on our expenditure forecasts assessment. See: Ausgrid, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 19–20.

267 The Full Federal Court handed down its final directions on 4 July 2017.

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 proposed approach on the form of depreciation to be used when the NSW distributors' RABs are rolled forward to the commencement of the 2024–29 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.[268] 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 does not lose the full cost of any overspend and is not able to keep all the benefits of any

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

underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

5.1 AER's proposed position

We propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2024–29 regulatory control period for the NSW distributors. We consider this approach will provide sufficient incentives for the NSW distributors to achieve capex efficiency gains over the 2019–24 regulatory control period.

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.[269]

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.[270] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[271]

- 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 proposed position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB for the NSW distributors at the commencement of the 2024–29 regulatory control period. We note that the NSW distributors support our preliminary position to use the forecast depreciation approach to establish the opening RAB.[272] The CCP also agreed with our preliminary position on the depreciation approach.[273] We note the CCP's concern about any deviation from the straight-line depreciation method used to

269 NER, cl. S6.2.2B.

270 NER, cl. 6.4A(b)(3).

271 NER, cl. S6.2.2B.

272 Essential Energy, *Submission on the AER's preliminary framework and approach for NSW distributors*, 21 April 2017; Endeavour Energy, *Response to the AER preliminary framework and approach*, 21 April 2017, p. 6; Ausgrid, *Submission on AER preliminary F&A*, 27 April 2017, p. 20.

273 Consumer Challenge Panel 10, *Submission on preliminary framework and approach for NSW distributors*, 21 April 2017, p. 21.

forecast the depreciation building block.[274] We will consider such issues during the assessment of the regulatory proposal.

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.[275]

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
- 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 2019–24 regulatory control period will be established using forecast depreciation, as stated in our previous determination that applies to the NSW distributors for the 2015–19 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2024–29 regulatory control period therefore maintains the current approach. The NSW distributors are currently subject to a CESS and we propose to continue to apply the CESS in the 2019–24 regulatory control period. We discuss this in section 3.3.

For the NSW distributors, 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.[276] 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.

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274 Consumer Challenge Panel 10, *Submission on preliminary framework and approach for NSW distributors*, 21 April 2017, pp. 21–22.

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

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

6 Dual function assets

Dual–function assets are high voltage transmission assets forming part of the distribution network. Transmission network service providers usually operate these assets. Considering transmission assets as part of a distribution determination avoids the need for a separate transmission proposal. Where a network service provider owns, controls or operates dual-function assets, we are required to consider whether we should price these assets according to the transmission or distribution pricing principles.

Our decision is to continue the current pricing approaches. Current approaches reflect dual function asset materiality compared to total assets and allow cost reflective pricing for benefitting customers.

6.1 AER's decision

Our final F&A decisions on dual function asset pricing are binding on us and on NSW distributors for the 2019–24 regulatory control period.

Ausgrid

Our decision is to apply transmission pricing to Ausgrid's dual function assets.[277] This is consistent with the current approach and Ausgrid's preferences.[278]

Endeavour Energy

Our decision is to apply distribution pricing to Endeavour Energy's dual function assets. This is consistent with the current approach and Endeavour Energy's preference.[279]

Essential Energy

The NER do not require us to make a decision for Essential Energy. It does not own, operate or control dual function assets.[280]

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277 Relevant services conform to the definition under cl. 6.24.2 of the NER.

278 Ausgrid, *Letter to AER - Request to replace framework and approach paper*, October 2016, p. 9.

279 Endeavour Energy*, Letter to AER - Request to AER to update the framework and approach for the next regulatory control period, Attachment A*, October 2016, p. 1.

280 Essential Energy, *Letter to AER - Update to framework and approach paper for the 2019-24 regulatory control period*, October 2016, p. 3.

Table 3 Dual function assets and pricing approaches

	Ausgrid	Endeavour Energy	Essential Energy
Dual function assets ($m)	$2,020 million	$227 million	0
Proportion of distribution Regulatory Asset Base (%)	14%	5%	0
Current regulatory period pricing	Transmission	Distribution	n/a
Service provider preference	Transmission	Distribution	n/a
AER decision	Transmission	Distribution	n/a

6.2 AER's assessment approach

Dual function asset rules establish transmission pricing as the default approach where the assets form a material proportion of the distributor's regulatory asset base (RAB). The NER require us, in deciding pricing approaches, to consider impacts on distribution prices and consumption, production and investment. We may also account for other factors we consider relevant.

Our decisions on dual function assets incorporate two main stages. First, we must be satisfied that relevant assets conform to the NER definition. On this, we gave weight to distributor information and statements. Having satisfied ourselves on this first issue, we then considered alternative pricing approaches.

Distribution and transmission pricing represent different ways of recovering service costs. Under transmission pricing, distributors may allocate dual function asset costs to both a TNSP's broader customer base and the distributor's customers. However, under distribution pricing rules, distributors with dual function assets may not allocate costs to a TNSP.

Electricity supply costs transfer along the supply chain, or downstream, onto the next service provider in the process. Hence, generators pass generation costs to retailers who pass them to customers. In the same way, TNSPs pass their costs to distributors, who in turn pass those costs to retailers and then to customers. Costs may not be passed back up the supply chain from distributors to TNSPs, except under transmission pricing rules. Therefore, under distribution pricing rules, a distributor's own customers pay the full cost of dual function assets.

Because transmission networks are upstream of distribution networks, they usually service larger numbers of electricity consumers than distribution networks. Therefore, where TNSPs recover the same service costs, transmission pricing usually provides for lower per unit prices than distribution pricing. We note that this is not necessarily an appropriate outcome. The NER require us to determine efficient service costs. In principle, electricity consumers who stand to benefit from dual function assets should pay for those services.

In some cases, the potential transmission and distribution customer bases for cost recovery purposes are the same. In such cases, network service providers would recover dual function asset costs from the same number of customers. The AER expects that in such cases price impacts for individual customers under both pricing approaches would be equivalent.

We applied a three part test to determine application of either transmission or distribution pricing rules. First, we considered the value of dual function assets as a proportion of the distributor's RAB. Second, we considered whether regulating prices under distribution rules rather than transmission would:

- result in materially different prices for distribution customers
- impact on future consumption, production and investment decisions.

Third, we took into account other matters we considered relevant. Specifically, we considered cost reflectivity, or who benefits from the assets and administrative cost implications of changing the current approach. Customers benefitting from dual function assets should contribute to their cost recovery. The NER define dual function assets as supporting the higher voltage transmission network. Therefore, our default assumption is that a broader customer set than just the distributor's customers are benefiting from shared assets. We also consider that we should avoid administrative costs where possible. Finally, we consider the current approach should continue unless we identify sufficient reasons to change the approach.

6.3 Reasons for AER's decision

For the following reasons our decision is that transmission pricing will continue to apply to Ausgrid's dual function assets. At 14 per cent, the assets are clearly a material proportion of Ausgrid's RAB, justifying application of transmission pricing. Further, application of distribution pricing would materially impact Ausgrid's distribution customers and affect consumption, production and investment. In terms of cost reflectivity, Ausgrid's dual function assets support TransGrid's transmission network, so transmission pricing facilitates appropriate cost recovery. Additionally, maintaining the current transmission pricing approach avoids additional administrative costs.

For the following reasons, our decision is that distribution pricing would continue to apply to Endeavour Energy's dual function assets. At five per cent of Endeavour Energy's RAB, these are significantly less material than is the case for Ausgrid. Additionally, Endeavour Energy submitted that its dual function assets form transmission exit assets supporting only its own distribution network. This means that even under transmission pricing rules, full asset costs would be allocated to Endeavour Energy distribution customers. Therefore, changing the pricing approach to transmission pricing would not have a material impact on distribution prices. Changing the approach would also incur administrative costs.

We are not required to decide a pricing approach for Essential Energy, as it does not operate dual function assets.

Ausgrid

Our decision is that Ausgrid would continue to apply transmission pricing to its dual function assets.

Ausgrid operates assets conforming to the NER dual function asset definition. We reached this view, first, because Ausgrid reported that it currently operates assets conforming to the NER definition. As there are significant penalties for reporting incorrect information, we gave weight to Ausgrid's reported information. Second, Ausgrid's reported information is consistent with historic information on its dual function assets.

We then considered the materiality of dual function assets in terms of Ausgrid's RAB. At $2,020 million (nominal) or 14 per cent of Ausgrid's RAB, we consider Ausgrid's dual function assets are a material proportion of its RAB. The NER does not define 'material' in the context of dual function assets. We therefore applied its common meaning and considered the consumer price implications of this asset proportion. Removing such a proportion of Ausgrid's RAB would have a more than double-digit impact on customer prices. Such a price impact would clearly be significant or important to customers. As such, we consider 14 per cent is clearly a significant or important proportion of Ausgrid's total RAB.

We further consider that, wherever possible, end-use customers benefitting from specific network assets should bear the cost of those assets. Dual function asset rules, however, do not explicitly establish this principle. Rather, we must consider whether the dual function assets comprise such a material proportion of the RAB that the prices should be regulated through transmission pricing. To apply distribution pricing rules, a number of tests must be met, relating to asset proportions and consumer price impacts.[281] We therefore give weight to benefitting customers under our power to consider other issues.[282]

Under transmission pricing, dual function asset costs are appropriately directed to both Ausgrid's customers and the broader set of TransGrid customers. The NER define dual function assets as providing support to the higher voltage transmission network, in this case operated by TransGrid. Ausgrid reported it owns dual function assets. Our preliminary position is that Ausgrid's dual function assets are indeed supporting TransGrid's network, providing services both to Ausgrid and others. Under distribution pricing rules, only Ausgrid's customers would pay for its dual function assets. Therefore, substituting distribution pricing for the current transmission pricing approach would not be appropriate.

281 NER, cl. 6.25(b) and (c).
282 NER, cl. 6.25(c)(3).

We further consider that changing from the current transmission pricing approach may also increase Ausgrid's administrative costs. This is because changing the pricing approach would require changes to Ausgrid's processes and systems. Such administrative costs give weight to maintaining the current approach.

Our decision is therefore that the current pricing approach should be continued in the upcoming regulatory control period. This position is consistent with the current regulatory approach.

Endeavour Energy

Our decision is that Endeavour Energy would continue to apply distribution pricing to its dual function assets.

Endeavour Energy operates assets conforming to the NER dual function asset definition. Again, we reached this view on the basis of information submitted to us by Endeavour Energy which is also consistent with historical information. At $227 million or 5 per cent of its RAB, Endeavour Energy's dual function assets are a smaller proportion of its RAB than other distributors' dual function assets. For reasons set out below, Endeavour Energy's RAB valuations are less relevant than in other contexts.

In terms of the price impact of the alternative pricing approaches, we gave weight to Endeavour Energy's views:[283]

> The AER confirmed its decision from the 2009-14 F&A paper that distribution pricing would continue to apply to Endeavour Energy’s dual function assets in its Stage 1 2014-19 F&A paper. This was due to our dual function assets being an immaterial proportion of our overall regulated asset base. Further, these assets are dedicated to our distribution network meaning that separately pricing them as transmission assets would not have any material impact on our distribution prices. This is because these transmission charges would be wholly allocated to Endeavour Energy, which they currently are as part of our distribution network.
>
> We have updated the analysis provided to the AER in support of its decision in the 2014-19 F&A and attached it to this response. The updated analysis confirms that the relevant assets would remain an immaterial proportion of the overall asset base and be classified as exit equipment. Therefore, we consider there is no need to amend or replace the existing F&A in respect of this matter.

The NER specify that exit equipment, or exit assets, provide transmission 'prescribed exit services'.[284] Such assets link a transmission network to a transmission customer, or group of customers. In other words, electricity 'exits' the transmission network via such assets. The NER specify that a TNSP operating those services must attribute related costs to benefiting customers. In this case, Endeavour Energy's distribution customers are the only beneficiaries of its dual function assets. Transmission pricing rules would therefore allocate the full cost of Endeavour Energy's dual function assets to its own distribution customers.

283 Endeavour Energy*, Letter to AER - Request to AER to update the framework and approach for the next regulatory control period, Attachment A*, October 2016, p. 1.

284 NER, cl. 6A.22.

Endeavour Energy currently recovers full dual function asset costs from its distribution customers. Therefore, changing to transmission pricing would produce no material change in Endeavour Energy's distribution prices. Without an appreciable price difference, continuing distribution pricing would have little impact on future consumption, production and investment decisions.

We further consider that changing from the current distribution pricing approach may also increase administrative costs for Endeavour Energy. This is because changing the pricing approach would require changes to Endeavour Energy's processes and systems. Such administrative costs give weight to maintaining the current approach.

In light of the above, our decision is that distribution pricing should continue to apply. This position is also consistent with us giving weight to continuing the current approach.

Appendix A: List of submissions

- AER Consumer Challenge Panel (Sub-panel 10)
- Ausgrid
- Central NSW Regional Organisation of Councils (Centroc)
- CitiPower/Powercor
- Cotton Australia and NSW Irrigators' Council
- Endeavour Energy
- Essential Energy
- Origin Energy
- Red Energy and Lumo Energy
- SA Power Networks
- Western Sydney Regional Organisation of Councils (WSROC)
- Southern Sydney Regional Organisation of Councils (SSROC)

Appendix B: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[285]

- 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.[286]
- 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)[287]
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[288]
- any other relevant factor.[289]

285 NER, cl. 6.2.1(c).
286 NEL, s. 2F.
287 NER, cl. 6.2.1(c)(2).
288 NER, cl. 6.2.1(c)(3).
289 NER, cl. 6.2.1(c).

The NER specify additional requirements for services we have regulated before.[290] They are:

- There should be no departure from a previous classification (if the services have been previously classified); and
- If there has been no previous classification - the classification should be consistent with the previously applicable regulatory approach.

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[291]

- 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.[292]

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.

290 NER, cl. 6.2.1(d).
291 NER, cl. 6.2.2(c).
292 NER, cl. 6.2.2(c).

Appendix C: Proposed service classification of NSW distribution services 2019−24[293]

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
Common distribution services			
Common distribution services (formerly 'network services')	The suite of services involved in the use 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) or to support another distributor during an emergency event • network demand management for distribution purposes • training internal staff, accredited service providers (ASPs) and	Standard control	Standard control

293 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/Activities included	Further description	Current Classification 2014–19	Proposed classification 2019–24
	contractors undertaking direct control services • 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 metering • rectification of simple customer fault (e.g. fuse) relating to a life support customer. 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.			
Design related services	Activities includes: • provision of design information, design rechecking services in relation to connection and relocation works provided contestably • work of an administrative nature relating to work performed by Level 1 and Level 3 ASPs, including processing work • the provision of engineering consulting (related to the shared distribution network).	Alternative control	Alternative control (specific monopoly service)
Connection application related services	Activities include: • assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	• 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 agreements made under Chapter 5 of the NER.		
Contestable network commissioning and decommissioning	The commissioning and decommissioning of network equipment associated with ASP Level 1 contestable works. Includes equipment checks, tests and activities associated with setting or resetting network protection systems and the updating of engineering systems.	Alternative control	Alternative control (specific monopoly service)
Access permits, oversight and facilitation	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	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	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 of the network. • facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets. • provision of approved materials/equipment to ASPs for connection assets that will become part of the shared distribution network. • assessing an application from an ASP or manufacturer to consider approval of alternative material and equipment items that are not specified in the distributor's approved materials list.		
Notices of arrangement and completion notices	A distributor may be required to perform work of an administrative nature where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This may include receiving and checking subdivision plans and 88 B instruments, copying subdivision plans, checking and recording easement details, assessing supply availability, liaising with developers if errors or changes are required and preparing notifications of arrangement. A distributor may also be required to provide a completion notice (other than a notice of arrangement). This applies where the customer/developer or ASP requests distributor to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	meet contractual undertakings.		
Network related property services	Property tenure services related to obtaining deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with connection or relocation. Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.	Alternative control	Alternative control (specific monopoly service)
Site establishment services	Activities include, but not limited to: • Site establishment, including liaising with the Australian Energy Market Operator (AEMO) or market participants for the purpose of establishing NMIs in market systems, for new premises or for any existing premises for which AEMO requires a new NMI and for validation of and updating network load data. This includes processing and assessing requests for a permanently unmetered supply device. • Site alteration, updating and maintaining national metering identifier (NMI) and associated data in market systems. • NMI extinction, processing a request by the customer or their agent for permanent disconnection and the extinction of a NMI in market systems. • Confirming or correcting metering or network billing information in market business to business or network billing systems, due to insufficient or incorrect information received from retailers or metering providers.	Alternative control	Alternative control (specific monopoly service)
Network safety services	Examples include:	N/A	Alternative control (potentially contestable)

Service group/Activities included	Further description	Current Classification 2014–19	Proposed classification 2019–24
	• provision of traffic control services by the distributor where required • fitting of tiger tails, high load escort • de-energising wires for safe approach (e.g. for tree pruning) • work undertaken to determine the cause of a customer fault where there may be a safety impact on the network or related component • Neutral integrity test – where customers request the distributor to investigate the occurrence of mild electric shocks within a customer's premises to determine whether the fault exists within the customer's installation or on the network. A fee would be levied where the fault is within the customer's installation.		
Rectification works to maintain network safety	Activities include issues identified by the distributor and work involved in managing and resolving pre-summer bush fire inspection customer vegetation defects or aerial mains where the customer has failed to do so.	N/A	Alternative control (specific monopoly service)
Network tariff change request	Activities including a retailer's customer or retailer requesting an alteration to an existing network tariff (for example, a change from a Block Tariff to a Time of Use tariff), requiring the distributor to conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria. Where a distributor processes changes in its IT systems to reflect a tariff change request.	Alternative control	Alternative control (specific monopoly service)
Services provided in relation to a Retailer of Last Resort (ROLR) event	The distributors may be required to perform a number of services as a distributor when a ROLR event occurs. For example: Preparing lists of affected sites and reconciling data with AEMO	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	listings, arranging estimate reads for the date of the ROLR event, preparing final invoices and miscellaneous charges for affected customers, extracting customer data, providing it to the ROLR and handling subsequent enquiries.		
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.	N/A	Alternative control (specific monopoly service)
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 includes the costs of arranging, and the provision of, a security escort or police escort (where the cost is passed through to the distributor).	Alternative control	Alternative control (specific monopoly service)
Inspection services − Private electrical installations and accredited service providers (ASPs)	Inspection of and reinspection by a distributor, for safety purposes, of: • private electrical wiring work undertaken by an electrical contractor and contestable works undertaken by ASPs. • the investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of an ASP due to unsafe practices or substandard workmanship. • private inspection of privately owned low voltage or high voltage network infrastructure (i.e. privately owned distribution infrastructure before the meter).	Alternative control	Alternative control (specific monopoly service)
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	N/A	Alternative control

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	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.		
Security lights	Customer requested flood lighting services	Unclassified distribution service	Alternative control (potentially contestable)
Off-peak conversion	Customer requested alteration of load control equipment for the purposes of converting a customer from peak to off-peak electricity supply.	Alternative control	Alternative control (specific monopoly service)
Authorisation of ASPs	Includes annual authorisation of individual employees and sub-contractors of ASPs and additional authorisations at request of ASP and other administrative services performed by the distributor relating to work performed by an ASP.	Alternative control	Alternative control (specific monopoly service)
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); and • could impact the safety or security of the network.	N/A	Alternative control (specific monopoly service)
Termination of cable at zone substation – distributor required performance	The termination of cable at zone substations and first joint out, where: • a work health and safety assessment determines that an ASP should not be given the required access to the zone substation; and • the connection is fully dedicated to the specific customer connecting.	N/A	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
Metering services – The NSW distributors will remain responsible for the provision of type 5 and 6 meters up to 30 November 2017 in their respective distribution areas. They will continue to be responsible for those 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'.			
Type 1 to 4 metering services	Type 1 to 4 meters and supporting services are competitively available.	Unclassified	Unclassified
Type 5 and 6 meter provision (prior to 1 December 2017)	Recovery of the capital cost of type 5 and 6 metering equipment installed prior to 1 December 2017.	Alternative control	Alternative control (specific monopoly service)
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
Types 5 and 6 meter maintenance, reading and data services (legacy meters)	Meter maintenance covers works to inspect, test, maintain and repair meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services are those that involve the collection, processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the Rules.	Alternative control	Alternative control (specific monopoly service)
Special meter reading and testing (legacy meters)	Special meter reading and testing services include: • Special meter reading for type 5 and 6 meters and move in and move out metering reading (type 5 and 6 meters) • Type 5 meter final read on removed type 5 metering equipment	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	• Special meter test (for type 5 and 6 meters) • Type 5 and 6 non-standard meter data services • Type 5 and 6 current transformer testing.		
Emergency maintenance of failed metering equipment not owned by the distributor (contestable meters)	The distributor is called out by the 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.	Alternative control	Alternative control (specific monopoly service)
Meter recovery and disposal − type 5 and 6 (legacy meters)	Activities include: • at the request of the customer or their agent to remove and dispose of type 5 or 6 current transformer (CT) meters where a permanent disconnection has been requested. • disposing of type 5 or 6 whole current (WC) meters which may otherwise be removed and disposed of by the incoming metering provider.	N/A	Alternative control (specific monopoly service)
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.	N/A	Alternative control (specific monopoly service)
Customer requested provision	Customer requested provision of data in excess of requirements under	Alternative control	Alternative control (specific

Service group/Activities included	Further description	Current Classification 2014–19	Proposed classification 2019–24
of additional metering/consumption data	rule 28 of the National Electricity Retail Rules (two requests per annum are permitted under this rule).		monopoly service)
Connection services			
Premises connection assets	Includes any additions or upgrades to the connection assets located on the customer's premises which are contestable (Note: excludes all metering services). Premises connection assets can be further described as: A. Design and construction of premises connection assets (where these services are provided contestably). B. Part design and construction of connection assets that are not available contestably (generally as a result of safety, reliability or security reasons). Those parts of project works that are performed and funded by the distributor except where C applies. C. Part design and construction of connection assets where a customer requests that connection assets are designed and constructed to an increased standard (beyond that required by the distributors' standards and policies), and where those works are designed and constructed by the distributor (as a result of safety, reliability or security reasons).	A. Unclassified B. Standard control C. Unclassified	A. Unclassified B. Standard control C. Alternative control
Extensions	An enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a Network Service Provider that is: A. undertaken by a customer. B. undertaken by a customer but partly funded by a NSP (NSP	A. Unclassified B. Unclassified/standard	A. Unclassified B. Unclassified/standard

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	contribution would be classified as a standard control service while the customer funded component of the service would be unclassified). C. undertaken by a network service provider.	control based on contribution C. Standard control	control based on contribution C. Standard control
Augmentations	A. Any shared network enlargement/enhancement undertaken by a distributor which is not an extension. B. Any shared network enlargement/enhancement undertaken by a customer, but partly funded by a distributor (distributor contribution would be classified as a standard control service while the customer funded component of the service would be unclassified). C. Any shared network enlargement/enhancement undertaken by a customer. D. Any shared network enlargement/enhancement undertaken by a distributor where a customer requests that assets are designed and constructed to an increased standard (beyond that required by the distributors' standards and policies).	A. Standard control B. Unclassified/standard control based on contribution C. Unclassified D. Unclassified	A. Standard control B Unclassified/standard control based on contribution C. Unclassified D. Alternative control
Reconnections/Disconnections	Disconnection and/or reconnection services (some provided in accordance with the National Energy Retail Rules). Examples include (but are not limited to): • Disconnection visit (site visit only) • Disconnection visit (disconnection completed - technical) • Disconnection visit (disconnection completed) • Pillar box/pole top disconnection - completed • Reconnection/disconnection outside of business hours	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	• Vacant property - site visit only • Vacant property disconnection (disconnection completed) • Shared service fuse replacement • Rectification of illegal connections • Temporary connections • Remove or reposition connection • Single phase to three phase		
Public lighting			
Public lighting	Provision, construction and maintenance of public lighting and emerging public lighting technology.	Alternative control	Alternative control
Unregulated distribution services			
Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc.).	N/A	Unclassified distribution service
Contestable metering support roles	Includes metering coordinator (except where the distributor is the initial metering coordinator), metering data provider and metering provider for meters installed or replaced after 1 December 2017.	N/A	Unclassified distribution service
Non-standard connection services	Customer requested services that typically occur at the time of connection. For example, the following requested customer services: • asset relocations requested by a third party (including a customer)	N/A	Unclassified distribution service

Service group/Activities included	Further description	Current Classification 2014−19	Proposed classification 2019−24
	which are unlikely to impact on the safety or security of the network. • conversion of aerial bundled cable (i.e. reducing the number of overhead lines by combining them). • reserve or duplicate supplies (beyond what a distributor is required to provide). • unless a work health and safety assessment determines that an ASP should not be given the required access, the termination of cable at zone substations and first joint out (where the connection is fully dedicated to the specific customer connecting).		
Provision of training to third parties for non-network related access	Training programs provided to third parties which are not ASPs or contractors.	N/A	Unclassified distribution service
Type 5 and 6 meter data management to other electricity distributors	The provision of type 5 and 6 meter data management to other electricity distributors.	Unclassified distribution service	Unclassified distribution service
Non-distribution services – Although this table relates to distribution services, we have included the below non-distribution services provided by Essential Energy for clarity.			
Generation assets	Non-standard control generation assets. E.g. Nymboida and Oaky Hydro and Western Plains Zoo Solar in NSW	N/A	Non-distribution service
Water	Broken Hill and Water Rights as (the former) Nymboida Hydro Plant in NSW	N/A	Non-distribution service