



Preliminary framework and approach

**Power and Water corporation
Regulatory control period
commencing 1 July 2019**

March 2017

© Commonwealth of Australia 2017

This work is copyright. In addition to any use permitted under the Copyright Act 1968, all material contained within this work is provided under a Creative Commons Attributions 3.0 Australia licence, with the exception of:

- the Commonwealth Coat of Arms
- the ACCC and AER logos
- any illustration, diagram, photograph or graphic over which the Australian Competition and Consumer Commission does not hold copyright, but which may be part of or contained within this publication. The details of the relevant licence conditions are available on the Creative Commons website, as is the full legal code for the CC BY 3.0 AU licence.

Requests and inquiries concerning reproduction and rights should be addressed to the Director, Corporate Communications,
Australian Competition and Consumer Commission,
GPO Box 3131,
Canberra ACT 2601
or publishing.unit@acc.gov.au.

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585165

Email: AERInquiry@aer.gov.au

Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) regarding this paper by the close of business, 21 April 2017.

Submissions should be sent electronically to: [NTPowerWater2019@aer.gov.au](mailto:NTPowerWater2019@ aer.gov.au)

Alternatively, submissions can be mailed to:

Mr Chris Pattas

General Manager, Network Pricing, Policy and Compliance

Australian Energy Regulator

GPO Box 520

Melbourne VIC 3001

The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on the AER's website at www.aer.gov.au. For further information regarding the AER's use and disclosure of information provided to it, see the ACCC/AER Information Policy, October 2008 available on the AER's website.

Enquiries about this paper, or about lodging submissions, should be directed to the Network Regulation branch of the AER on (03) 9290 1444.

Contents

Request for submissions	ii
Shortened forms	5
Overview	6
Classification of distribution services	8
1 Classification of distribution services	12
1.1. AER's preliminary position	12
1.2. AER's assessment approach	13
1.3. Reasons for AER's preliminary position	16
2 Control mechanisms	28
2.1. AER's preliminary position	28
2.2. AER's assessment approach	28
2.3. AER's reasons — control mechanism and formulae for standard control services	32
2.4. AER's reasons — control mechanism for alternative control services	40
3 Incentive schemes	44
3.1. Service target performance incentive scheme	44
3.2. Efficiency benefit sharing scheme	45
3.3. Capital expenditure sharing scheme	48
3.4. Demand management incentive scheme and innovation allowance mechanism	50
4 Expenditure forecast assessment guideline	56
5 Depreciation	58
5.1. AER's preliminary position	59
5.2. AER's assessment approach	59
5.3. Reasons for AER's preliminary position	59

Appendix A: Rule requirements for classification61

Appendix B: Preliminary classification of NT distribution services.....63

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
current regulatory control period	1 July 2014 to 30 June 2019
DMIA	demand management innovation allowance
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
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules As in force in the Northern Territory
next regulatory control period	1 July 2019 to 30 June 2024
NUoS	network use of system
Opex	operating expenditure
RAB	regulatory asset base
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).

Power and Water Corporation (PWC) operates the sole monopoly electricity transmission and distribution network in the Northern Territory. The network contains the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and business. PWC designs, constructs, operates and maintains the electricity network for electricity consumers in the Northern Territory.

We will make regulatory decisions on the revenue that PWC can recover from its customers. We determine its revenue by an assessment of its efficient costs and forecasts. Our assessment is based on regulatory proposals submitted by the network business in advance of a five year regulatory control period, in this case beginning 1 July 2019. The regulatory proposal sets out PWC's view on its expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues. To be clear, our F&A and decision on these issues will be made pursuant to the National Electricity Rules (Northern Territory). Therefore, references to the NER in our documents for PWC refer to the NER as in force in the Northern Territory.¹

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. The network business is then provided with incentives to outperform the revenue we determine. The network business retains any savings for a period of 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 the Northern Territory. 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.

The AER was officially transferred responsibility for Northern Territory electricity network regulation on 1 July 2015.² The 2019–24 regulatory control period will be our first determination of PWC's regulatory proposal. Accordingly, this is the first F&A paper for PWC under the NER. PWC operates both electricity distribution and transmission assets in the Northern Territory. Ordinarily this would require separate distribution and transmission determinations, notwithstanding that a single operator provides both types of network

¹ See: [http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-\(Northern-Territory\)](http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-(Northern-Territory)).

² As part of the NT Government's Electricity Market Reform

services.³ However, in this case electricity transmission assets operated by PWC have been deemed by the Northern Territory Government to be treated as distribution assets for the purposes of economic regulation.⁴ We will therefore make a single distribution determination for PWC as the operator of distribution and transmission assets in the Northern Territory.

Following release of this Preliminary F&A we will consult with interested parties before issuing our final F&A by 1 August 2017. Table 1 summarises the PWC determination process.

Table 1 PWC distribution determination process

Step	Date
AER publishes preliminary position F&A for PWC	March 2017
AER to publish final F&A for PWC	By 1 August 2017
PWC to submit regulatory proposal to AER	31 January 2018
AER to publish Issues paper and host public forum	March/April 2018*
Submission on regulatory proposal close	May 2018
AER to publish draft decision	September 2018
PWC to submit revised regulatory proposal to AER	December 2018
Submissions on revised regulatory proposal and draft decision close	January 2019*
AER to publish PWC determination for regulatory control period	April 2019

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

Source: NT NER, chapter 6.

This overview sets out our preliminary 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 and operating expenditure
- expenditure forecasting tools to test PWC's regulatory proposal
- how we will calculate depreciation of PWC's regulatory asset base
- how we will price transmission assets (dual function assets).

³ TasNetworks is an example of a single operator of distribution and transmission networks, for which we will make two separate determinations, one distribution determination and one transmission determination, albeit within a single administrative process.

⁴ Section 9 [Declaration of local distribution systems] of the National Electricity (Northern Territory)(National Uniform Legislation) Act , July 2016.

Our approach to some of the above matters could be impacted by the outcome of reviews into previous determinations which are currently before the Federal Court. The timing of the results of those reviews is uncertain.

We summarise below our intended 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 distribution services provided by PWC. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Where there is considerable scope to take advantage of market power, our regulation is more prescriptive. Less prescriptive regulation is required where prospect of competition exists. In some situations we may remove regulation altogether—unregulated distribution services must be provided through a separate affiliate to the distributor following the introduction of our Ring-Fencing Guideline.⁵ In broad terms, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be provided outside of the regulated network business, unless it applies for, and receives, a waiver under the ring-fencing guideline.

Table 2 provides an overview of the different classes of distribution services for the purposes of economic regulation under the NER.

Table 2 Classifications of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that 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 by the local distributor.	We set service specific prices to enable the distributor to recover the full 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	Distributors and customers are able to negotiate prices according to a framework established by the NER. We are available to arbitrate if

⁵ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

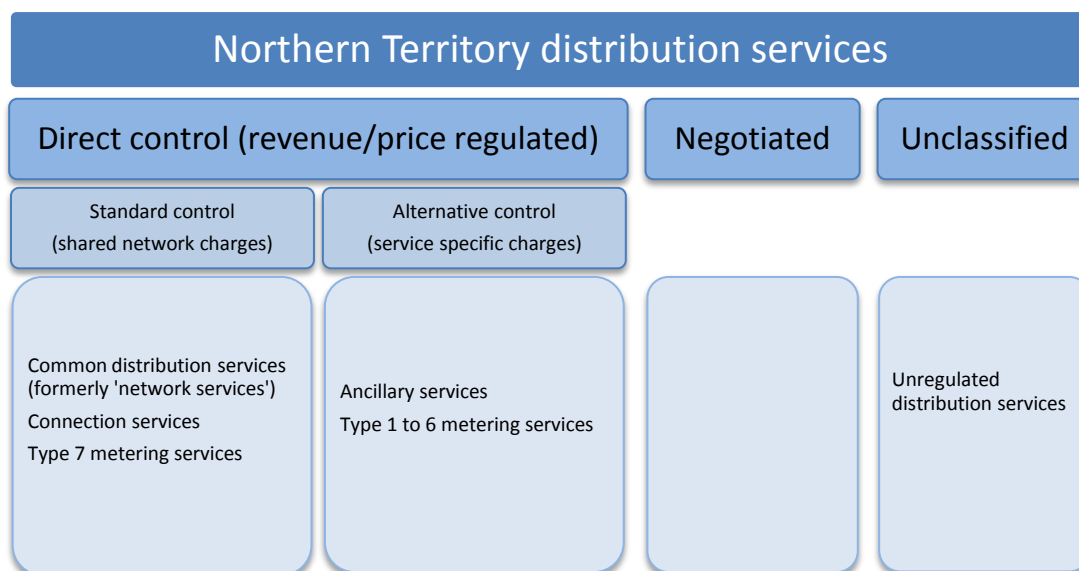
	the provision of those services.	necessary.
Unclassified service	Services that are not distribution services or services ⁶ that are contestable.	We have no role in regulating these services.

Source: AER

Our preliminary position is to change the classification of some NT 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, create consistency across jurisdictions as far as practicable and predictability in how new distribution services might be classified.

Our proposed service classifications for PWC are set out in figure 1 below.

Figure 1 AER proposed classification of PWC distribution services



Source: AER

Our final F&A decision on service classification is not binding for our determination on PWC's 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. This preliminary F&A represents our initial views on the classification of services but is subject to change due to policy modifications being considered by the NT Government.

Control mechanisms

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.⁷ We may only accept or approve control

⁶ A distribution service is a service provided by means of, or in connection with, a distribution system.

⁷ NER, cl. 6.2.5(a).

mechanisms in a distributor’s regulatory proposal if they are consistent with our final F&A.⁸ In deciding control mechanism forms, we must select one or more from those listed in the NER.⁹ 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 preliminary position on the form of control mechanisms for PWC is:

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

For standard control services the NER mandate the basis of the control mechanism must be the prospective CPI-X form or some incentive-based variant.¹⁰

Our final F&A decision on the form of control is binding. We may only vary our decision on control mechanisms in response to unforeseen circumstances.

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 preliminary position is to apply the following available incentive schemes to PWC:

- Efficiency Benefit Sharing Scheme
- Capital Expenditure Sharing Scheme
- Demand Management Incentive Scheme

We are not proposing to apply the Service Target Performance Incentive Scheme to PWC for the 2019–24 regulatory control period due to the unavailability of reliable historic supply interruption data.

Our final F&A approach on the application of incentive schemes is not binding on us or PWC.

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline¹¹ is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our preliminary position is to apply the guidelines, including its information requirements, to PWC in the upcoming regulatory control period.

⁸ NER, cl. 6.12.3(c).

⁹ NER, cl. 6.2.5(b).

¹⁰ 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.

¹¹ AER, *Expenditure Forecast Assessment Guideline for Distribution*, November 2013.

Our expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of PWC's regulatory proposal. 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.

Depreciation

When we roll forward PWC's regulatory asset base (RAB) for the upcoming regulatory control period we must adjust for depreciation. Our preliminary position is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RAB as at 1 July 2024. In combination with our proposed application of the CESS this approach will maintain incentives for PWC to pursue capital expenditure 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 NT customers, like the cost of other transmission assets. Distribution pricing rules recover costs from only the customers of a specific distribution network.

All of PWC's high voltage transmission assets are specified to be part of its distribution system.¹² Thus PWC's transmission assets cannot be classified as dual function assets.

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

¹² National Electricity (Northern Territory)(National Uniform Legislation) Act. Section 9 and Schedule 2- Declaration of local distribution systems. This includes PWC's Darwin to Katherine 132kV power line.

1 Classification of distribution services

This chapter sets out our preliminary position on the classification of distribution services provided Power and Water Corporation (PWC) in the Northern Territory (NT) for 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,¹³ we may classify services so that we:

- directly control prices of some distribution services¹⁴
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

This is the first time we have considered PWC's service classification as regulation of PWC transitions from jurisdictional regulation administered by the NT Utilities Commission under the Network Access Code.¹⁵ Our classification decisions therefore determine which services we will regulate and how PWC will recover the cost of providing those regulated services.

We are also aware that 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.¹⁶ While the AEMC's consideration of these rule change requests is ongoing, we have developed preliminary 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.

1.1 AER's preliminary position

Our preliminary position is to group distribution services provided by PWC for the 2019–24 regulatory control period as:

- common distribution services
- ancillary services
- metering services
- connection services
- unregulated distribution services.

¹³ Reference to the NER means the National Electricity Rules as in force in the Northern Territory, Version 6. See: [http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-\(Northern-Territory\)](http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-(Northern-Territory)).

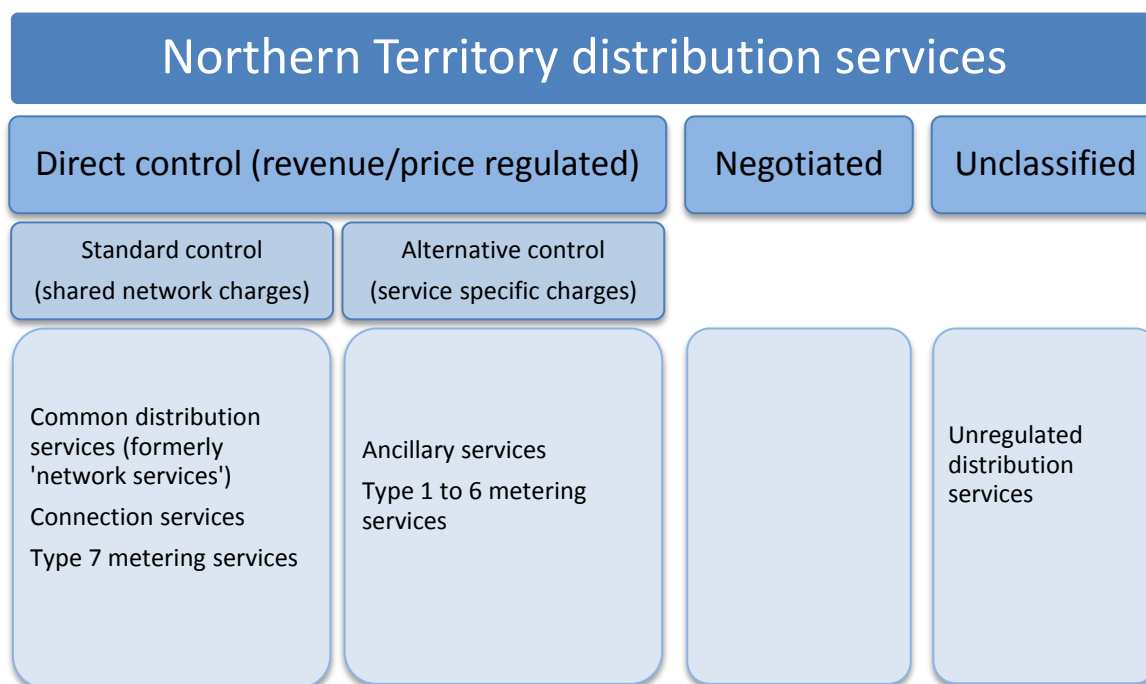
¹⁴ Control mechanisms available for each service depend on their classification. Control mechanisms available for direct control services are listed by clause 6.2.5(b) of the NER. These include caps on revenue, average revenue, prices and weighted average prices. A fixed price schedule or a combination of the listed forms of control are also available. Negotiated services are regulated under part D of chapter 6 of the NER.

¹⁵ See: <http://www.utilicom.nt.gov.au/Electricity/conduct/Pages/default.aspx>.

¹⁶ 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.

Figure 1.1 summarises our preliminary classification PWC's distribution services. Our assessment approach and reasons follow. Appendix B contains a detailed list of services, service descriptions and proposed service classifications.

Figure 1.1 AER proposed approach to classification of PWC's 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 groups¹⁷ – 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

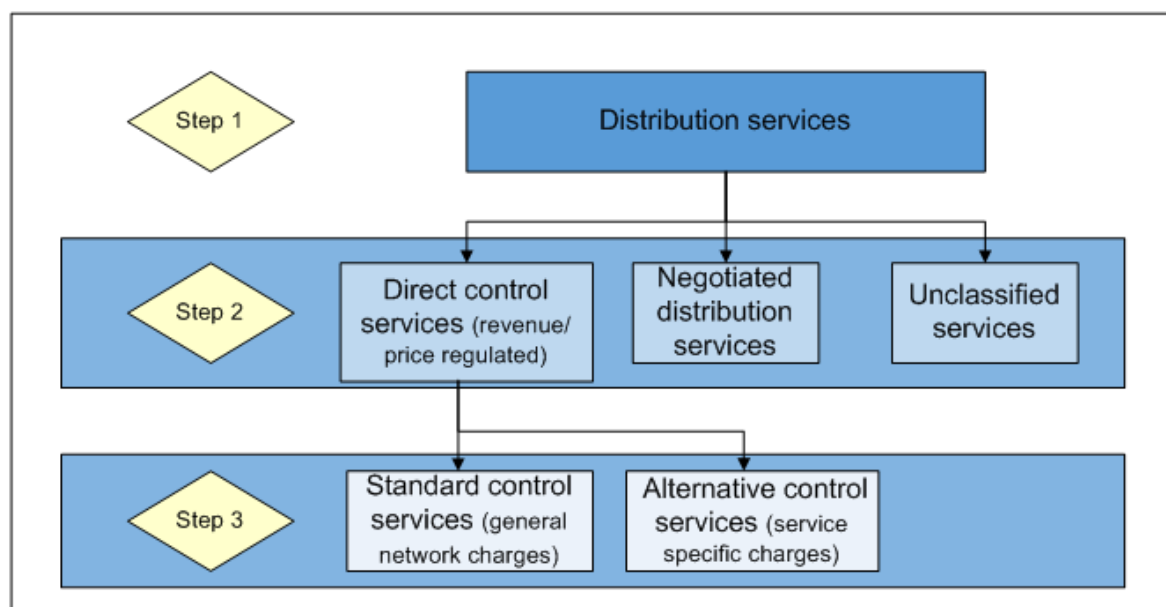
¹⁷ NER, cl. 6.2.1(b).

is similar in nature it would require the same regulatory treatment. As a result, a new service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for classification 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 service. New services (within a regulatory control period) that do not clearly belong to an existing service classification grouping are to be treated as 'not classified'.

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.

As illustrated by figure 1.2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER define a distribution service as a service provided by means of, or in connection with, a distribution system.¹⁸ A distribution system is a 'distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.¹⁹

¹⁸ NER, chapter 10, glossary.

¹⁹ NER, chapter 10, glossary.

- 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.²⁰ We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The NER also requires us to consider the previous form of regulation applied to services and the desirability of consistency with the previous approach.²¹

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.²² 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 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:²³

- 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.²⁴

Our classification decisions determine how distributors will recover the cost of providing services.²⁵ Distributors recover standard control service costs by averaging them across all customers using the shared network. This shared network charge forms the core distribution component of an electricity bill. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. We set service specific prices to enable the distributor to recover the full 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

²⁰ NER, cl. 6.2.1(c); NEL, s. 2F.

²¹ NER, cl. 6.2.1(c).

²² NER, cl. 6.2.2(c).

²³ NER, cl. 6.2.2(d).

²⁴ NER, cll. 6.2.1(d) and 6.2.2(d).

²⁵ 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).

- 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 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.²⁶

The following points are to assist stakeholders understand the change in classification terminology from the NT Utilities Commission determination²⁷ to our preliminary F&A made pursuant to the NER:

- A regulated network access service is equivalent to a direct control, standard control service classification under the NER.
- An excluded network access service not subject to effective competition is equivalent to a direct control, alternative control service classification under the NER.
- An excluded network access service subject to effective competition is equivalent to the service not being classified under the NER and therefore not subject to regulation by us.

1.3 Reasons for AER's preliminary position

This section sets out our preliminary service classification and reasons for PWC's 2019–24 regulatory control period for:

- common distribution services

²⁶ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

²⁷ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, Appendix A at p. 160. See: <http://www.utilicom.nt.gov.au/PMS/Publications/US-FD-NPD14-A.pdf>.

- ancillary services
- metering services
- connection services
- unregulated distribution services.

Appendix B contains a detailed table of our preliminary classification of PWC's distribution services.

1.3.1 Common distribution services

This service group was formerly called 'network services'.²⁸ However, to avoid confusion with the defined terms in chapter 10 of the NER, we propose to rename this service group 'common distribution services'. We are open to alternative suggestions for the name of this service group that refers to the services distributors provide over a shared distribution network to all customers connected to it.

Common distribution services are concerned with providing a safe and reliable electricity supply to customers.²⁹ Currently in the Northern Territory, these services are classified as standard control services.³⁰ Common distribution services are intrinsically tied to the network infrastructure and the staff and 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.

Our preliminary position is to classify common distribution services as direct control services. PWC holds an electricity distribution licence which is the only distribution license in place for the Northern Territory.³¹ Under section 17 of the *Electricity Reform Act* (NT) 2000, a person may only distribute electricity if they hold a licence authorising them to do so. These arrangements create a regulatory barrier, preventing third parties from providing common distribution services.³² 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.³³ Our preliminary position is to retain the current standard control classification for

²⁸ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 24.

²⁹ NER, Chapter 10 glossary.

³⁰ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163.

³¹ Licences are issued by NT Utilities Commission.

³² NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).

³³ NER, cl. 6.2.2(a).

common distribution services.³⁴ There is no potential to develop competition in the market for common distribution services because of the barriers outlined above.³⁵ There would be no material effect on administrative costs for us, PWC, users or potential users by continuing this classification.³⁶ We currently classify common distribution services (or 'network services') in all other NEM jurisdictions as standard control services.³⁷ Further, distributors provide common distribution services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.³⁸

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, our preliminary position is to not classify this service, treating it as an unregulated distribution service. This is because the cost of these works may be recovered 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.

Therefore, our preliminary 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. 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. In fact, the distributors are incentivised under the Efficiency Benefit Sharing Scheme to make operating expenditure (opex) savings of this nature.³⁹ 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 the regulatory asset base and treated like a capital contribution. This prevents distributors from recovering the cost of emergency repairs twice—as a standard control charge across the broader customer base and from the responsible third party.

Our preliminary position is a departure from the Utilities Commission's decision to classify emergency recoverable work as a direct control⁴⁰ and alternative control service.⁴¹ However,

³⁴ NER, cl. 6.2.2(c)(3) and (4).

³⁵ NER, cl. 6.2.2(c)(1).

³⁶ NER, cl. 6.2.2(c)(2), (3).

³⁷ NER, cl. 6.2.2(c)(4).

³⁸ NER, cl. 6.2.2(c)(5).

³⁹ For further information on the operation and application of the AER's Efficiency Benefit Sharing Scheme (EBSS) see: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-incentives-guideline>

⁴⁰ NER, cl. 6.2.1(d)(1). We have retained a direct control classification.

⁴¹ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163; NER, cl. 6.2.2(c)(3) and (4).

our proposed approach will result in a consistent treatment of emergency recoverable works across NEM jurisdictions.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use. 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.⁴²

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.⁴³

The new arrangements will commence on 1 December 2017. However, we are aware that the NT Government is still working to develop and implement a policy to support new and replacement meters in line with minimum service specifications proposed by the AEMC.⁴⁴ This may potentially lead to modifications to the metering contestability framework set out in chapter 7 of the NER (NT). At this time we are uncertain what these changes might be. Consequently, this will impact our proposed classification of metering services as we move to our final F&A. The key consideration is whether PWC will be mandated to provide metering services as the monopoly service provider as opposed to third parties consistent with the competitive framework. If PWC is the monopoly service provider, economic regulation will be necessary, and we would classify the service as a direct control service. Whereas if the service was competitively provided, we would not classify the service and it would be unregulated.

Type 1 to 6 metering services

Large customers use 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. In the NT, standard type 1 to 4 meters are currently classified as regulated network access services, which is equivalent to standard control services. This is because PWC is currently the monopoly provider of type 1 to 4 meters in the NT. This contrasts to most other NEM jurisdictions where they are competitively available⁴⁵ and hence, unclassified.

Our preliminary position is to classify type 1 to 4 metering services as alternative control services.

PWC is also currently the monopoly provider of standard type 5 (interval) and 6 (accumulation) meters. However, from 1 December 2017 (and therefore before the

⁴² AEMC, *Competition in metering services information sheet*, 26 November 2015.

⁴³ AEMC, *Competition in metering services information sheet*, 26 November 2015.

⁴⁴ Legislative Assembly of the Northern Territory, *Sessional Committee on the Northern Territory's Energy Future, Electricity Pricing Options*, December 2018, p. 58 at para 4.2 and recommendation 2.

⁴⁵ NER, cll. 7.2.3(a)(2) and 7.3.1.A(a).

commencement of the next regulatory control period on 1 July 2019), metering services across the National Energy Market will become contestable. While the design on a metering contestability framework in the NT is currently unclear, there is a prospect that during the next regulatory control period households and other small customers who traditionally use these meter types may wish to change the type of meter they have.

Therefore, we propose to unbundle type 1 to 6 metering services from standard control services and classify them as alternative control services. This approach would make our classification consistent with the AEMC's Power of Choice Review. The AEMC's recommendations included:⁴⁶

- current metering arrangements need reform to promote investment in better metering technology and promote customer choice
- metering costs should be unbundled from shared network charges.

Therefore, our preliminary position is to classify type 1 to 6 meter provision as an alternative control service. Further, we will separately classify type 5 and 6 meters installed before 1 July 2019 as an alternative control service. Under this approach, PWC may still recover the capital cost of type 5 and 6 metering equipment installed before 1 July 2019 where customers choose to switch meter types and they have not have paid the full capital cost of their meter. Our approach is consistent with our determinations for all NEM distributors except Victoria where an advanced metering infrastructure program exists.

Further, if charges for type 1 to 6 metering services remain bundled in common distribution services, the commencement of any metering contestability framework will be far less effective. This is because customers would not have transparency around the pricing of metering services provided by PWC and whether it would be economical to switch to an alternative meter or metering provider. We do not consider this scenario to be in the long term interests of customers.

Ancillary services – Metering

PWC may be required to provide other services to support the metering contestability framework.

Some examples include:

- Type 5 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.⁴⁷
- 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

⁴⁶ AEMC, Consultation paper — National electricity amendment (expanding competition in metering and related services), April 2014

⁴⁷ 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.

disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.⁴⁸

- Type 5 to 7 non-standard meter data services – the provision of information of the customer's energy consumption or distributor charges following the request from a retailer, a retailer's customer or a retailer customer's authorised agent.⁴⁹

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

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

Type 7 metering services

Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. Charges associated with type 7 metering services relate to the process of estimating electricity use. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation, and the light bulb wattage. PWC is the monopoly provider of type 7 metering services in the NT.⁵⁰

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.⁵¹ 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.⁵²

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.⁵³

In preliminary discussions some distributors have raised the possibility of creating a transitional metering coordinator, provider and data provider services. This is because each distributor will be appointed as the metering coordinator as at 1 December 2017.⁵⁴ Some

⁴⁸ 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.

⁴⁹ This wording has been added to reflect AMEO Metering Data Provision Procedures that the NSW distributors will be subject to.

⁵⁰ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163.

⁵¹ NER, 6.2.2(c)(1).

⁵² Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163.

⁵³ 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.

⁵⁴ 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

network service providers suggest that by creating this service and classifying it as an alternative control service, it would obviate the need to ring-fence a transitional service until, for example, alternative metering coordinators are appointed. However, we consider that pre-existing type 5 and 6 metering services already encompasses these roles and is reflected in the alternative control service charges.

As noted above, the metering framework for NT is yet to be finalised and this includes how these roles will be performed in the NT. We appreciate that this is a new issue therefore welcome stakeholder comments.

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach is to not classify these services.⁵⁵ That is, we propose to treat them as unregulated distribution services. We appreciate the distributors' view of creating an alternative control service until the market for these services is established. However, contestability in metering means there is significant potential to develop competition for the provision of these services.⁵⁶ For example, to create a transitional metering coordinator service and classify it as an alternative control service may cause customers confusion about their ability to source a metering coordinator from the competitive market and set their own commercial arrangements. This would not be in the long term interests of consumers and would not promote the policy goals of the metering contestability framework.⁵⁷

From a ring fencing perspective, the provision of these services will need to be separated from the provision of direct control services. We may consider (subject to an application) ring-fencing waivers around office and staff sharing obligations where there are no third party competitors (for a time).⁵⁸ While this may increase the administrative costs of the distributor in establishing an affiliate to provide these services, we consider the benefits to customers in being about to secure services from a competitive market outweighs this cost.⁵⁹ However, the precise application of our ring-fencing guideline in the Northern Territory is still being considered by the NT Government and PWC.

1.3.3 Connection services

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

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

November 2015, p. 129.

⁵⁵ NER, chapter 10, glossary; *Ergon Energy Corporation Ltd v Australian Energy Regulator* [2012] FCA 393

⁵⁶ NER, cl. 6.2.1 (c)(1), NEL, ss. 2F(a), (d), (e), (f), (g) and NER, cl. 6.2.2(c)(1).

⁵⁷ 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.

⁵⁸ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

⁵⁹ NER, cl. 6.2.2(c)(2).

- extend the network to reach a person's premises (extension).

PWC's connection services as described above are currently classified as direct control and further, as standard control services.⁶⁰ Our preliminary position is to continue this classification.

PWC holds the only electricity distribution licence to provide connection services in the NT. This licensing arrangement results in a high regulatory barrier preventing third parties from providing connection services.⁶¹ Additionally, we consider the scale and scope of resources available to PWC also prevent the competitive provision of connection services by a third party. We therefore consider that PWC possesses significant market power in the provision of connection services.⁶²

For these reasons, we consider that classifying connection services as direct control services is the most appropriate outcome.

We intend to retain the current classification of connection services as standard control services. We consider that there is no basis to move away from this classification as:

- There is little, if any, prospect for competition in the market for connection services. That is, we are not aware of any NT Government initiatives to introduce contestability for connection services in the 2019–24 regulatory control period. Therefore, our classification will not influence the potential for competition.
- There would be no material effect on administrative costs to us, PWC, users or potential users. This is because classifying connection services as standard control services is consistent with the current regulatory approach.
- We currently regulate connection services in most other NEM jurisdictions under a direct form of control. We do not regulate some New South Wales connection services, which are competitively available.
- The nature of basic connection services is that in most instances, the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers. However, application of our Connection Charge Guideline⁶³ provides a safety net for the broader customer base. That is, the requirement of the requesting customer to make a capital contribution to a service protects the broader customer base from incurring additional costs for services of no benefit to them.
- We classify standard connection services in Queensland and South Australia as standard control services.⁶⁴ In Victoria and Tasmania, we classify standard connection services as alternative control services.⁶⁵

⁶⁰ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 24.

⁶¹ NEL, s. 2F(a).

⁶² NEL, s. 2F(d).

⁶³ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012.

⁶⁴ AER, *Final decision, Queensland distribution determination 2015–20*, October 2015, p. 13-19; AER, *Final decision, South*

We must act on the basis that there should be no departure from a previous classification unless another classification is clearly more appropriate.⁶⁶ We consider the current standard control classification supports the operation of Chapter 5A and the Guideline and provides a framework for consumers to understand where additional contributions may be required. We intend to classify connection services including premises connections, extensions and network augmentation, as standard control services.

PWC provides a basic connection to anyone requesting to connect to the network to use electricity. Connections over and above the cost of a basic connection may trigger a capital contribution. For example, a customer may seek a temporary connection to complete renovations to their house, or an upgrade from single phase to three-phase connection. The cost of these types of services is directly attributable to the customer requesting the service. On that basis, we intend to classify these ancillary connection services as alternative control services (as part of the broader 'ancillary services' service group' discussed at section 1.3.4). This means the customer requesting the service will pay the full cost of the service. This would avoid other customers having to bear the cost of customer specific service requests. The list of relevant services is set out in appendix B.

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 PWC's distribution network. Therefore, similar to common distribution services only PWC may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than PWC providing ancillary services in their respective distribution area.⁶⁷ Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which PWC provides these services. These factors contribute to the view that PWC possesses significant market power in providing ancillary services.⁶⁸

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 PWC provides these services to specific customers.⁶⁹ As such, the full cost of each ancillary service is directly attributable to an individual customer.⁷⁰ This results in costs that are more transparent for customers.

⁶⁵ *Australia distribution determination 2015–20*, October 2015, p. 13-15

⁶⁶ AER, *Final decision, Victorian DNSPs distribution determination 2016–20*, May 2016, p. 13-20; AER, *Draft decision, TasNetworks distribution determination 2017–19*, p. 13-13.

⁶⁷ NER, cl. 6.2.2(d).

⁶⁸ NEL, s. 2F(a).

⁶⁹ NEL, s. 2F.

⁷⁰ NER, cl. 6.2.2(c)(5).

⁷⁰ NER, cl. 6.2.2(c)(5) - this includes a small number of identifiable 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, PWC, users or potential users.⁷¹ This is because classifying ancillary services as alternative control services is consistent with the current approach.⁷²

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

1.3.5 Unregulated distribution services

Unregulated distribution services is the term we use to describe distribution services which we have not classified as either direct control or negotiated services.⁷³ 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.⁷⁴ 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.⁷⁵ Under our ring-fencing guideline, any unregulated distribution service would be provided by a separate affiliate. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage. As noted above, the precise application of the ring-fencing guideline in the NT is yet to be finalised. Nevertheless, PWC is encouraged to consider what unregulated distribution services it might provide.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services. Affiliated entities may provide other electricity services. For the purposes of this preliminary F&A we are not addressing interactions with other regulatory frameworks in detail as these are set out in the explanatory statement to the ring-fencing guideline.⁷⁶

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

⁷² Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, pp. 160–165.

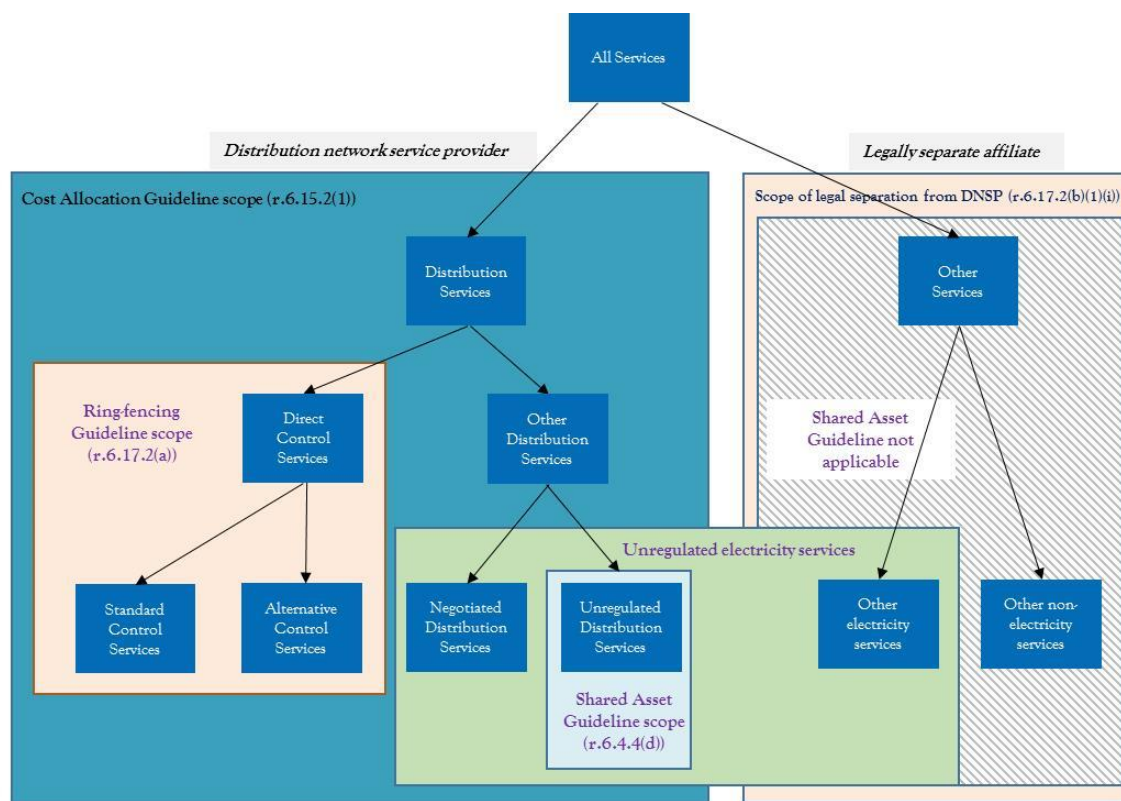
⁷³ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

⁷⁴ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

⁷⁵ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

⁷⁶ 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) will need to consider 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.

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

Distributors, when considering what unregulated distribution services they offer, should refer to the examples contained in the explanatory statement to the ring-fencing guideline⁷⁷ and their unregulated revenue streams. For example, a distributor may earn additional revenue from say NBN Co. by permitting NBN Co. to hang its wires from the same poles. The service is 'providing access to electricity poles'. Similarly, some other access to a network asset that forms part of the regulatory asset base (RAB) may be rented to a third party. The service for classification is 'access to a RAB asset'.

We expect that there will be a number of distribution services that distributors may propose to provide on a ring-fenced basis that are currently unregulated services.

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

2 Control mechanisms

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.⁷⁸ This chapter sets out our preliminary positions, together with our reasons on the form of control mechanisms to apply to PWC's direct control services for the 2019–24 regulatory control period. This chapter also sets out our preliminary 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.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.⁷⁹ 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.⁸⁰

2.1 AER's preliminary position

Our preliminary position is to apply the following control mechanisms 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.

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 mechanisms⁸¹
- the formulae to give effect to the control mechanisms
- the basis of the control mechanisms.⁸²

The NER sets out the control mechanisms that may apply to both standard and alternative control services.⁸³

- a schedule of fixed prices

⁷⁸ NER, cl. 6.2.5(a).

⁷⁹ NER, cl. 6.12.3(c).

⁸⁰ NER, cl. 6.12.3(c1).

⁸¹ NER, cl. 6.2.5(b).

⁸² NER, cl. 6.2.6(a).

⁸³ NER, cl. 6.2.5(b).

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)⁸⁴

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

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

A revenue cap sets a 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 may 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 cap on the revenue recovered by a distributor in any given year. That is, if revenue recovered under the WAPC is greater than (less than) the expected revenue, the distributor keeps (loses) that additional (shortfall) revenue.

- revenue yield control (average revenue cap)

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

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

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

In considering our preliminary positions on the control mechanisms for PWC's standard control services, we have only considered the continuation of the revenue cap, or adoption

⁸⁴ 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.

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 AGL proposed should apply to the standard control services for distributors in other jurisdictions.⁸⁵ We did not receive a submission from PWC.

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

We have not considered a WAPC as our previous considerations on this type of control mechanism noted the incentives for distributors to systematically recover revenue above efficient cost recovery resulting in higher bills for consumers.⁸⁶ We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.⁸⁷

We have also not considered a hybrid approach as our previous considerations considered the higher administrative costs outweigh the potential benefits of this form of control.⁸⁸

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

Our consideration on the control mechanisms for PWC's alternative control service is based on whether there is reason to depart from a price cap control which is applied to almost all other distributors' alternative control services. Our considerations are against 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 will 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
- the regulatory arrangements in the 2014 NT Network Price Determination⁸⁹

⁸⁵ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016.

⁸⁶ 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.

⁸⁷ NEL, s. 7.

⁸⁸ For example, see: AER, *Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

⁸⁹ Utilities Commission, *2014 Network Price Determination - Part A – Statement of Reasons*, April 2014; Utilities Commission, *2014 Network Price Determination - Part B – Network Price Determination*, April 2014.

- 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.⁹⁰

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

2.2.2 Alternative control services

In determining a control mechanism to apply to alternative control services, we will consider 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 of us, the distributor and users or potential users
- the regulatory arrangements in the 2014 NT Network Price Determination⁹¹
- 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 or cost reflectivity allows 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 allow 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.⁹² 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 or incorporate a pass through mechanism.⁹³

⁹⁰ NER, cl. 6.2.6(a).

⁹¹ Utilities Commission, *2014 Network Price Determination - Part A – Statement of Reasons*, April 2014; Utilities Commission, *2014 Network Price Determination - Part B – Network Price Determination*, April 2014.

⁹² NER, cl. 6.2.6(b).

⁹³ NER, cl. 6.2.6(c).

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

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

Our preliminary position is to maintain a revenue cap for PWC's standard control services for the 2019–24 regulatory control period. We consider the application of a revenue cap control mechanism best addresses the factors set out under clause 6.2.5(c) of the NER.

We consider that a revenue cap will result in minimal additional administrative costs and allow for consistency of regulatory arrangements for standard control services both across regulatory periods and across jurisdictions.

We also consider that a revenue cap will 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 instability 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.⁹⁴ We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

Our preliminary position is that it is likely that efficient tariff structures can be developed and implemented under all types of control mechanisms. We note 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.

Previously, our 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.⁹⁵ 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 to be 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:

⁹⁴ NER, cl. 6.2.5(c)(1).

⁹⁵ 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.

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

A distributor's tariff structure statement sets out the tariff structures it can apply over a regulatory control period.⁹⁶ The tariff structure statement should show how a distributor applied the distribution pricing principles⁹⁷ 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:⁹⁸

the tariffs that a distributor charges for provision of direct control services to a retail customer should reflect the distributors' 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.⁹⁹

Generally, a distributor is required to submit a tariff structure statement when submitting its regulatory proposal.¹⁰⁰ However, the NER permitted submission of the initial tariff structure statements outside the regulatory proposal process due to the timing of the rule changes.¹⁰¹ 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.

Our assessment of these initial tariff structure statements and the tariff structures contained within found that many distributors were introducing forms of more cost reflective tariff structures such as demand based tariffs. In this initial assessment we found no evidence to suggest that ActewAGL's average revenue cap or the revenue caps applied by other distributors inhibited the ability to develop or implement efficient tariff structures. Therefore, with regard to efficient tariff structures, we presently consider that they 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 on a

⁹⁶ NER, cl. 6.18.1A(a)(3).

⁹⁷ 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).

⁹⁸ NER, cl. 6.18.5(a).

⁹⁹ NER, cl. 6.12.3(k).

¹⁰⁰ NER, cl. 6.8.2(a).

¹⁰¹ NER, cl. 11.76.2(a).

control mechanism needs to be weighed against the other factors under clause 6.2.5(c) of the NER.

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

2.3.2 Administrative costs

In deciding on a control mechanism, the NER require us to have regard to the possible effects of the control mechanism on administrative costs.¹⁰² 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 PWC's standard control services would best address clause 6.2.5(c)(2) of the NER. The continuation of a revenue cap would impose minimal additional administrative costs for us, PWC or users. We consider only minor adjustments are needed in transitioning from PWC's current revenue cap to the revenue cap that is applied to distributors already regulated under the NER. For example, we note our preliminary position revenue cap control formula as set out in figure 2.1 is not dissimilar to that applied to PWC currently.¹⁰³

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

2.3.3 Regulatory arrangements in the 2014 NT Network Price Determination

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements in the 2014 NT Network Price Determination.¹⁰⁴ We note maintaining a revenue cap control mechanism for PWC's standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(3) of the NER than an alternative control mechanism.

¹⁰² NER, cl. 6.2.5(c)(2).

¹⁰³ Utilities Commission, *2014 Network Price Determination - Part B – Network Price Determination*, April 2014, Schedules 4 and 5, pp. 51–55.

¹⁰⁴ NER, cl. 6.2.5(c)(2A).

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.¹⁰⁵ We consider maintaining a revenue cap control mechanism for PWC's standard control services provides for consistent regulatory arrangements for these services across jurisdictions.

We note that apart from ActewAGL, currently all other electricity distributors' who are subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. Therefore maintaining a revenue cap control mechanism for PWC will ensure consistent regulatory arrangements for these services across most jurisdictions.

However, we note our preliminary position in the preliminary F&A for ActewAGL for the 2019–24 regulatory control period is to transition the control on ActewAGL's standard control services to a revenue cap. Should this occur, then all distributors' standard control services will be subject to a revenue cap control mechanism.

We note price caps are not applied to standard control services in any jurisdiction. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(4) of the NER than an alternative control mechanism.

2.3.5 Revenue recovery

We consider that a control mechanism should give a distributor an opportunity to recover efficient costs. We also consider that 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.¹⁰⁶

In the concurrent F&A processes, AGL submitted that we review the control on distributors' revenues in light of uncertainty around future network demand and utilisation.¹⁰⁷ 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.

¹⁰⁵ NER, cl. 6.2.5(c)(4).

¹⁰⁶ 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.

¹⁰⁷ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

We also consider that under a revenue cap that distributors have an incentive to reduce their costs 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, we consider that 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 incur revenues above efficient cost recovery.¹⁰⁸ The systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.¹⁰⁹ We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹¹⁰

Therefore, in terms of efficient revenue recovery, on balance we considered that a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.¹¹¹

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 consumers' ability to manage bills and retailers' ability to manage risks incurred from changes to network tariffs which they then package into retail plans for customers.

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 requires various annual price adjustments regardless of the control mechanism.¹¹²

Within a regulatory control period, we consider an average revenue cap or price caps will deliver more overall price stability than a revenue cap. The increased instability 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, under a revenue cap falling demand creates price increases.¹¹³ The reverse happens with increasing

¹⁰⁸ For example, see: AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67; AER,

¹⁰⁹ 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.

¹¹⁰ NEL, s. 7.

¹¹¹ NEL, s. 7.

¹¹² These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from transmission network service providers.

¹¹³ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

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

We have somewhat addressed this issue in our recent determinations by applying a rolling unders and overs account which includes an additional true up for the estimated under and over recovery of revenues for the year in between (year $t-1$).¹¹⁴ 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 instability across regulatory control periods, we consider an average revenue cap can result in greater price instability compared to a revenue cap.¹¹⁵ 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 preliminary position is to maintain a revenue cap control mechanism for PWC's 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 instability.

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.¹¹⁶ 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.

¹¹⁴ For example, see: AER, *Final Decision, CitiPower distribution determination 2016 to 2020: Attachment 14—Control mechanisms*, May 2016, Appendix A, pp. 18–19.

¹¹⁵ AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 67–69.

¹¹⁶ Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

As stated above, AGL submitted that a price cap control mechanism be considered in light of uncertainty around network demand and utilisation.¹¹⁷ 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.¹¹⁸ We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales such as 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 because of falling demand or consumption.

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.¹¹⁹ 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.¹²⁰ Below is proposed formula to apply to PWC's standard control services revenues. We consider that the formula gives effect to the revenue cap.

Figure 2.1 Preliminary positions revenue cap to be applied to PWC's standard control services

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

$$TAR_t = AAR_t + I_t + B_t + C_t \quad t = 1, 2, \dots, 5$$

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

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

where:

¹¹⁷ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

¹¹⁸ That is, demand side management projects that result in a reduction in future network expenditure greater than the cost of implementing the demand side management projects.

¹¹⁹ NER, cl. 6.8.1(b)(2)(ii).

¹²⁰ NER, cl. 6.12.3(c1).

TAR_t is the total allowable revenue in year t.

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

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

t is the regulatory year.

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

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

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

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

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

S_t is the s-factor adjustments for regulatory year t due to the application of the STPIS.¹²¹

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹²² 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.

¹²¹ 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.

¹²² 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 is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

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

Our preliminary position is to apply caps on the prices of individual services (price caps) in the 2019–24 regulatory control period to all of PWC's alternative control service.¹²³ We consider the application of price caps for PWC's alternative control services best meets the factors set out under clause 6.2.5(d) of the NER. We propose classifying the following services as alternative control services:

- type 1 to 6 metering services
- ancillary services.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.¹²⁴ 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 preliminary position 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 preliminary positions 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 preliminary consideration of the relevant factors is set out below.

2.4.1 Influence on the potential to develop competition

We consider that the control mechanism for alternative control services will not have a significant impact on potential competition development. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 of the F&A 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.

¹²³ The Consumer Challenge Panel supported maintaining price caps for alternative control services. Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

¹²⁴ NER, cl. 6.2.6(c).

We consider that PWC is likely to incur additional administrative costs in the short run regardless of type of control mechanism as there is currently no control mechanism applied to the PWC services which our preliminary F&A classifies as alternative control services.

However, we consider the application of price caps to these services is likely to incur the least amount of additional administrative burden for PWC as the current development for these prices most closely resembles the development of prices under a price cap.¹²⁵

2.4.3 Regulatory arrangements in the 2014 NT Network Price Determination

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements in the 2014 NT Network Price Determination.¹²⁶

We note that there is current no control mechanism applied PWC's alternative control services but rather that clause 72(4) of The Electricity Networks (Third Party Access) Code 2015¹²⁷ requires them to be provided on fair and reasonable terms.¹²⁸ If PWC and the customer cannot reach agreement then the AER has a role in determining what constitutes fair and reasonable. We consider this type of regulation is a negotiated service.

Under the NER, an alternative control service must be subject to price or revenue control.¹²⁹ As such, the negotiation of price for these services cannot continue. Therefore, our decision on the control mechanism for PWC's alternative control services over the 2019–24 regulatory control period must be weighed against the other factors under clause 6.2.5(d) of the NER.

2.4.4 Desirability of consistency between regulatory arrangements

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

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

2.4.5 Cost reflective prices

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

¹²⁵ PWC, *Power Networks: 2016–17 Electricity network tariffs and charges and future price trends*, June 2016, p. 8.

¹²⁶ NER, cl. 6.2.5(d)(2A).

¹²⁷ The Electricity Networks (Third Party Access) Code, which is a schedule to the *Electricity Networks (Third Party Access) Act*.

¹²⁸ Utilities Commission, *2014 Network Price Determination - Part A – Statement of Reasons*, April 2014, pp. 25–26.

¹²⁹ NER, cl. 6.2.5(a).

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for alternative control services.¹³⁰ 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.¹³¹

Below are our preliminary positions price cap formulae which will apply to PWC's alternative control services.

Figure 2.2 Preliminary positions price cap formulae to be applied to PWC's type 1–6 metering and ancillary fee based services

$$\bar{p}_t^i \geq p_t^i \quad i=1,\dots,n \text{ and } t=1, 2,\dots,5$$

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

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 Cities¹³² 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.

¹³⁰ NER, cl. 6.8.1(b)(2)(ii).

¹³¹ NER, cl. 6.12.3(c1).

¹³² 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

Figure 2.3 Preliminary positions price cap formula to be applied to PWC's ancillary quoted services

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Materials}$$

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 Cities¹³³ from the December quarter in year t-2 to the December quarter in year t-1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-1

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-2

minus one.

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

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

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

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

¹³³ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

3 Incentive schemes

This chapter sets out our preliminary position on the application of a range of incentive schemes to the PWC for the next regulatory control period. At a high level, our preliminary position is to apply the:

- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme.

3.1 Service target performance incentive scheme

This section sets out our reasons for not applying the service target performance incentive scheme (STPIS) to PWC in the next regulatory control period.

Our national distribution STPIS¹³⁴ provides a financial incentive to distributors to maintain and improve service performance. The STPIS 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 distributors' 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 customers¹³⁵ experiencing service below a predetermined level.¹³⁶

3.1.1 AER's preliminary position

PWC advised that its auditor has identified a number of issues with its current outage record system. It is in the process of establishing a new outage management system, which is expected to complete by the end of 2017.

In accordance with clauses 3.1 (b) and 5.1(b) of STPIS, due to the unavailability of reliable historic supply interruption data, we propose not to apply the s-factor component of the STPIS to PWC in the next regulatory control period. However, we will be collecting relevant

¹³⁴ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

¹³⁵ Except where a jurisdictional electricity GSL requirement applies.

¹³⁶ 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.

data during the course of the 2019–24 regulatory control period in order to establish suitable targets for the following regulatory control period.

We will also not apply the GSL component if PWC remains subject to a jurisdictional GSL scheme. In Northern Territory, the Utilities Commission sets out GSLs that apply to PWC.¹³⁷ Our intention is to not create duplication or compromise PWC's 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 Northern Territory code remain in place. We will amend this position if the Northern Territory Government advises that these arrangements will cease to apply.

3.2 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (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 network users. Consumers benefit from improved efficiencies through lower regulated prices. This section sets out our preliminary position and reasons on how we intend to apply the EBSS to PWC in the next regulatory control period.

3.2.1 AER's preliminary position

We intend to apply the EBSS¹³⁸ to PWC for the 2019–24 regulatory control period.

Our distribution determination for PWC for the 2019–24 regulatory control period will specify if and how we will apply the EBSS.

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing between distributors and network users of opex efficiency gains and efficiency losses.¹³⁹ We must also have regard to the following factors in developing and implementing the EBSS:¹⁴⁰

- 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.

¹³⁷ Utilities Commission, *Guaranteed Service Level Code*, 1 January 2012.

¹³⁸ AER, *Efficiency benefit sharing scheme*, 29 November 2013.

¹³⁹ NER, cl. 6.5.8(a).

¹⁴⁰ NER, cl. 6.5.8(c).

3.2.3 Reasons for AER's preliminary position

We will make our decision whether or not to apply the EBSS to PWC in the 2019–24 regulatory control period in our determination. The decision to apply the EBSS will depend on whether we will use PWC's revealed costs in the 2019–24 regulatory control period to forecast opex in the 2024–29 regulatory control period.

Why we would apply the EBSS

This section set outs reasons why we would only apply the EBSS if we use a revealed cost forecasting approach to forecast opex for the 2024–29 regulatory control period.

The EBSS must provide for a fair sharing of efficiency gains and losses.¹⁴¹ Under the scheme distributors and consumers receive a benefit where a distributor makes an ongoing reduction to its opex during a regulatory control period. Similarly, both share any ongoing increases in opex.

Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.¹⁴² The EBSS provides a continuous incentive for distributors to achieve opex efficiencies throughout the subsequent period. This is because the distributor receives carryover payments so it retains any efficiency gains or losses it makes within the regulatory period for the length of the carryover period. This is regardless of the year in which it makes the gain or loss.¹⁴³

This continuous incentive to improve efficiency encourages efficient and timely opex throughout the regulatory control period, and reduces the incentive for a distributor to inflate opex in the expected base year. This provides an incentive for distributors to reveal their efficient opex which, in turn, allows us to better determine efficient opex forecasts for future regulatory control periods.

The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.¹⁴⁴ For instance the combined effect of our forecasting approach and the EBSS is that opex efficiency gains or losses are shared approximately 30:70 between distributors and consumers. This means for a one dollar efficiency saving in opex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

An example that shows how the EBSS operates is set out in our explanatory statement to our EBSS. It illustrates how the benefits of a permanent efficiency improvement are shared approximately 30:70 between a network service provider and consumers.¹⁴⁵

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.¹⁴⁶ Where opex incentives are balanced with capex incentives, a

¹⁴¹ NER, cl. 6.5.8(a).

¹⁴² NER, cll. 6.5.8(c)(3) and 6.5.8(a).

¹⁴³ NER, cl. 6.5.8(c)(2).

¹⁴⁴ NER, cl. 6.5.8(c)(1).

¹⁴⁵ See also: AER, *Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers*, Appendix A, 29 November 2013, pp. 25–26.

¹⁴⁶ NER, cl. 6.5.8(c)(4).

distributor does not have an incentive to favour opex over capex, or vice-versa. The CESS is a symmetric capex scheme with a 30 per cent incentive power. This is consistent with the incentive power for opex when we use an unadjusted base year approach in combination with an EBSS. During the subsequent period when the CESS and EBSS are applied, incentives will be relatively balanced, and distributors should not have an incentive to favour opex over capex or vice versa. We discuss the CESS further in section 3.3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives.¹⁴⁷

Expenditure on non-network alternatives generally takes the form of opex rather than capex. Successful non-network alternatives should result in the distributor spending less on capex than it otherwise would have. Non-network alternatives and demand management incentives are discussed further in section 3.4

When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor will receive a net reward for implementing the non-network alternative.¹⁴⁸ This is because the rewards and penalties under the EBSS and CESS are balanced and symmetric. In the past where the EBSS operated without a CESS, we excluded expenditure on non-network alternatives when calculating rewards and penalties under the scheme. This was because distributors may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.¹⁴⁹

Why we would not apply the EBBS

This section set outs reasons why we would not apply the EBSS if we considered it was not likely that we would use a revealed cost forecasting approach to forecast opex for the 2024–29 regulatory control period.

The use of revealed opex in determining the opex allowance for the following period is a key factor in whether the EBSS will achieve its stated objective. If it is uncertain whether we will rely on PWC's revealed costs in period one to forecast opex in period two, there will not be a strong reason to apply the EBSS in period one. For example, if PWC's revealed costs in the 2014–19 regulatory control period are still higher than the opex incurred by a benchmark efficient service provider, we will be unlikely to use revealed costs to forecast opex for the 2019–24 regulatory control period. In that case, we will be unlikely to apply the EBSS, to avoid network users being worse off.

If a business considers we will substitute an opex forecast not based on the revealed cost in a single base year, it has an incentive to significantly underspend in the base year to maximise its revenues. That is, the business can increase its EBSS carryover knowing the

¹⁴⁷ NER, cl. 6.5.8(c)(5).

¹⁴⁸ When the distributor spends more on opex it receives a 30 per cent penalty under the EBSS. However, when there is a corresponding decrease in capex the distributor receives a 30 per cent reward under the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward.

¹⁴⁹ Without a CESS the reward for capex declines over the regulatory period. If an increase in opex corresponded with a decrease in capex, the off-setting benefit of the decrease in capex depends on the year in which it occurs.

underspend will not reduce its opex forecast for the following period.¹⁵⁰ In this case, the benefit to the distributor of reducing opex in the base year would be greater than the opex underspend. Consumers would not receive a share of the underspend and would in fact be worse off. This outcome is contrary to the NER which requires that the EBSS must provide for a fair sharing of efficiency gains and losses between a distributor and customers.¹⁵¹

3.3 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. This section sets out our preliminary position and reasons for how we intend to apply version 1 (dated 29 November 2013) of the CESS to PWC in the next regulatory control period.

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend 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 to work out what the distributor's share of any underspend or overspend amount should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amount.¹⁵² 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 or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

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

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,¹⁵³ to PWC in the next regulatory control period.

¹⁵⁰ In our explanatory statement to the EBSS, we discuss why we should exclude the expenditure categories not forecast using a single year revealed cost forecasting method from the EBSS to prevent network users being worse off. AER, *Explanatory statement - efficiency benefit sharing scheme*, November 2013, pp. 18-19.

¹⁵¹ NER, cl' 6.5.8(a).

¹⁵² 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.

¹⁵³ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

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:¹⁵⁴

- make that decision in a manner that contributes to the capex incentive objective set out in the NER¹⁵⁵
- consider the CESS principles,¹⁵⁶ capex objectives,¹⁵⁷ other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

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

3.3.3 Reasons for AER's preliminary position

PWC is not currently subject to a CESS. PWC proposed that the CESS should not apply in the next regulatory control period.¹⁵⁸ PWC considered that the CESS (and EBSS) is best applied when the market and supporting regulatory framework are stable and predictable to avoid unexpected and unintended consequences.¹⁵⁹ PWC further stated that their regulatory environment is in a state of flux and the status of regulatory instruments is not expected to be fully known until at least mid-2018.¹⁶⁰ PWC also referred to regulatory precedent, where the EBSS was not applied to Ausgrid in its current regulatory control period.¹⁶¹ We understand that any uncertainty regarding PWC's regulatory arrangements will be resolved prior to the next regulatory control period such that the application of ex-ante incentives (including the CESS) is likely to contribute to the capex objective. In the context of our Ausgrid decision, as noted by PWC, we decided not to apply the CESS in the current regulatory control period on the basis that the EBSS is intrinsically linked to the 'revealed cost' method of forecasting opex. However, as the method of forecasting capex is not directly linked to the revealed cost approach this issue does not arise in relation to the application of a CESS. Our reasoning for our preliminary position is detailed below.

As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.¹⁶² The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.¹⁶³ We are also proposing to apply forecast depreciation, which we discuss further in chapter 5.

¹⁵⁴ NER, cl. 6.5.8A(e).

¹⁵⁵ NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

¹⁵⁶ NER, cl. 6.5.8A(c).

¹⁵⁷ NER, cl. 6.5.7(a).

¹⁵⁸ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 1.

¹⁵⁹ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 3.

¹⁶⁰ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 3.

¹⁶¹ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 4.

¹⁶² AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

¹⁶³ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

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 EBSS which PWC may be subject to in the next regulatory control period.

For capex, the sharing of underspend and overspend amounts happens at the end of each regulatory 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.¹⁶⁴ Because of this a distributor may choose to spend capex earlier, or 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 distributors with an ex ante incentive to spend only efficient capex. Distributors that make efficiency gains will be rewarded through the CESS. Conversely, distributors that make efficiency losses will be penalised through the CESS. In this way, distributors 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.

3.4 Demand management incentive scheme and innovation allowance mechanism

This section sets out our preliminary position and reasons for applying our new demand management incentive scheme (DMIS) and demand management allowance mechanism (DMIA) to PWC in the next regulatory control period.

A recent rule change by the AEMC¹⁶⁵ has change the application of the existing DMIS that applied to distributors in the past (other than PWC because this is the first time they will be regulated under the NER). On 20 August 2015, the AEMC published its new Demand Management Incentive Scheme Rule Determination. There are two parts of the framework under the NER, these being the Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance mechanism (DMIA).

The goal of the new scheme is to provide distributors with an incentive to encourage efficient demand management, both in implementing commercially viable demand management initiatives and in conducting research and development.

¹⁶⁴ 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 any underspend in the regulatory period, the greater its reward will be.

¹⁶⁵ AEMC, *Rule Determination: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, August 2015.

Under the new Rule, the objective of the DMIS and DMIA is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The objective under the previous DMIS was to “provide incentives for Distribution Network Service Providers 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 objective of the new DMIS is therefore different than the previous demand management scheme.

The DMIS and DMIA will not affect the classification of distribution services, the form of the control mechanisms as specified in this F&A, the formulas that give effect to those mechanisms.

We are currently developing a new scheme and allowance mechanism, and in January 2017 published a DMIS and DMIA Consultation paper.¹⁶⁶ We will continue consultation, which includes PWC, in developing the DMIS and DMIA. At this stage, we expect to make the new DMIS and DMIA by 30 September 2017.

3.4.1 AER's preliminary position

Our preliminary position is to apply the new DMIS and DMIA currently being developed under a separate process to PWC in the next regulatory control period.

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 PWC.¹⁶⁷ These are:

DMIS Objective

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

Benefits to consumers

- the DMIS should reward PWC 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.

¹⁶⁶ AER, *Consultation Paper- Demand management incentive scheme and innovation allowance mechanism*, January 2017.

¹⁶⁷ NER, cl. 6.6.3(c).

- 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 preliminary position on DMIS

This section outlines the reasons for our preliminary position to apply the DMIS to PWC in the next 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 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. 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.¹⁶⁸ 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 be designed so it can provide an incentive to DNSP to undertake non-network initiatives relating to demand management. The development of such incentives will need to consider the impacts of control mechanisms in the provision of incentives, that the design of the DMIS will ensure that non-network options do relate to and are likely to achieve demand management outcomes, and that such initiatives are cost efficient. A range of mechanisms are being considered in developing a scheme that would contribute to the achievement of the DMIS objective.¹⁶⁹ The mechanisms are discussed in our DMIS review Consultation Paper¹⁷⁰.

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

¹⁶⁸ 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.

¹⁶⁹ NER, cl. 6.6.3(c)(1).

¹⁷⁰ AER, *Consultation Paper- Demand management incentive scheme and innovation allowance mechanism*, January 2017.

cost savings to retail customers.¹⁷¹ The NER recognise that these net cost savings to retail customers could be via the net economic benefits delivered from implementing relevant non-network options¹⁷² so we must remain mindful of the potential impact of the DMIS on consumers. The DMIS will be designed so that the long term benefits expected to result from the scheme exceed the costs to consumers resulting from any associated adjustment to regulated revenues. It is recognised though that the operation of the scheme may result in benefits that accrue over multiple periods. We recognise that the DMIS operation may involve consideration of the benefits and costs of implementing alternative options.

Balanced incentives

We intend to assess projects, for which distributors apply for DMIS funding, using an appropriate set of criteria that will balance the incentives between expenditure on network options and non-network options relating to demand management. The DMIS must also be designed so the costs to consumers resulting from the associated adjustment to regulated revenues do not exceed the long term benefits expected to result from the scheme, and the net economic benefits across all participants in the market are taken into account. In striking the appropriate balance, it must be recognised that the operation of the scheme may result in cost impacts within a regulatory control period where the benefits are unlikely to be revealed until later periods.

The objective of the DMIS design will be to select and encourage the implementation of demand management initiatives which are likely to provide long term efficiency gains to energy consumers that will outweigh any short term price increases.

The DMIS could promote selected initiatives which reduce investment in new infrastructure through either deferral of, or removal of the need for, network augmentation and or expansion expenditures. The DMIS could also be used to implement appropriate initiatives which result in a more efficient use of existing infrastructure.

We may design the DMIS to provide incentives for DNSPs to conduct demand management which are additions to those present within the broader regulatory framework.

The DMIS will be designed so all costs recovered from other sources will be excluded from incentive payments under the DMIS. We have had regard to the effect that the application of the scheme will have on the incentives created by the EBSS, CESS and STPIS, and vice versa in the development of the DMIS. We will also avoid the imposition of any penalties as part of the DMIS.

3.4.4 AER's assessment approach to the DMIA

The NER require us to take several factors into account in developing and implementing a DMIA for PWC.¹⁷³ These are:

DMIA Objective

¹⁷¹ NER, cl. 6.6.3(c)(2).

¹⁷² NER, cl. 6.6.3(c)(3).

¹⁷³ NER, cl. 6.6.3A(c).

- The DMIA should provide Power and Water Corporation 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 DMIA should provide a reasonable level of the allowance considering the long term benefit to retail customers. The DMIA should only provide funding that is not available from any another source, including under a relevant distribution determination
- The DMIA will require distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance.

3.4.5 Reasons for AER's preliminary position on DMIA

This section outlines the reasons for our preliminary position to apply the DMIA to PWC in the next 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.

DMIA Objective

The revised NER has resulted in a modification of the objective of the allowance component of the demand management scheme, so that we will design the DMIA to provide funding for research and development in demand management projects that have the potential to reduce long term network costs.

We will need to 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 DMIA design will ensure projects are selected for funding that are clearly aimed at implementing non-network options that will reduce demand or peak demand, and that have the potential to reduce long term network costs.

The DMIA design will ensure selection of 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 DMIA. For example, clarification of innovative tariff trials may be required.

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

The design of the DMIA will require distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance. Publication of such reports enables the knowledge gained from DMIA 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 assessment guideline (the EFA guideline)¹⁷⁴ including the information requirements applicable to PWC for the 2019–24 regulatory control period. We propose applying the EFA guideline as it sets out our expenditure assessment approach developed and consulted upon during the Better Regulation program. The EFA guideline outlines the assessment techniques we will use to assess a network service provider's proposed expenditure forecasts, and the information we require from the network service provider.

The EFA guideline utilises a nationally consistent reporting framework allowing us to compare the relative efficiencies of network service providers and decide on efficient expenditure allowances. The NER require PWC to advise us by 30 November 2017 of the methodology it proposes to use to prepare forecasts.¹⁷⁵ In the F&A we must advise whether we will deviate from the EFA guideline.¹⁷⁶ This will provide Power and Water Corporation clarity on how we will apply the EFA guideline and the information it should include in its regulatory proposals. This contributes to an open and transparent process and provides stakeholders, as well as PWC, with predictability of our assessment, however circumstances may change that require us to reconsider our position.

The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of regulatory proposals by network service providers. We intend to have regard to the assessment tools set out in the guideline. The tool kit consists of:

- 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.¹⁷⁷

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

We welcome PWC's and stakeholders' submission to the preliminary F&A in which they can raise their concerns with the application of the current EFA Guideline. We will take into

¹⁷⁴ We developed the EFA guideline in accordance with clauses 6.4.5 of the NT NER. We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

¹⁷⁵ NER, cl. 6.8.1A(b)(1).

¹⁷⁶ NER, cl. 6.8.1(b)(2)(viii).

¹⁷⁷ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

consideration the issues raised in the F&A consultation process to determine how we may apply the EFA Guideline.

5 Depreciation

As part of the process of rolling forward a distributor's RAB to the start of the next regulatory control period, we update the RAB for actual capex incurred during the current regulatory control period and also adjust for depreciation. This chapter sets out our preliminary approach on the form of depreciation to be used when PWC's RAB is 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.¹⁷⁸ 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 underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

¹⁷⁸ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

5.1 AER's preliminary position

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

5.2 AER's assessment approach

We must decide at our determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.¹⁷⁹

We are required to 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.¹⁸⁰ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:¹⁸¹

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

5.3 Reasons for AER's preliminary position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB for PWC at the commencement of the 2024–29 regulatory control period.

We had regard to the relevant factors in the NER in developing the approach for deciding on the form of depreciation set out in our capex incentives guideline.¹⁸²

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:

¹⁷⁹ NER, cl. S6.2.2B.

¹⁸⁰ NER, cl. 6.4A(b)(3).

¹⁸¹ NER, cl. S6.2.2B.

¹⁸² AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

- 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 actual depreciation. This is consistent with the 2014 final determination made by the Utilities Commission of the Northern Territory that applies to PWC for the 2014–19 regulatory control period.¹⁸³ The use of forecast depreciation to establish the opening RAB at the commencement of the 2014–29 regulatory control period will therefore represent a change of approach. PWC is not currently subject to a CESS but we propose to apply the CESS in the 2019–24 regulatory control period. We discuss this further in section 3.3.

For PWC, 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.¹⁸⁴ 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.

¹⁸³ Utilities Commission of the Northern Territory, *2014 Network Price determination, Final determination, Part B—Network price determination*, April 2014, p. 12.

¹⁸⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19 and 20–21.

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.¹⁸⁵

- 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.¹⁸⁶
- 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)¹⁸⁷
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)¹⁸⁸
- any other relevant factor.¹⁸⁹

The NER specify additional requirements for services we have regulated before.¹⁹⁰ They are:

¹⁸⁵ NER, cl. 6.2.1(c).

¹⁸⁶ NEL, s. 2F.

¹⁸⁷ NER, cl. 6.2.1(c)(2).

¹⁸⁸ NER, cl. 6.2.1(c)(3).

¹⁸⁹ NER, cl. 6.2.1(c).

¹⁹⁰ NER, cl. 6.2.1(d).

- 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.¹⁹¹

- 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.¹⁹²

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.

¹⁹¹ NER, cl. 6.2.2(c).

¹⁹² NER, cl. 6.2.2(c).

Appendix B: Preliminary classification of NT distribution services

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
Common distribution services			
Common distribution services (formerly 'network services')	<p>The suite of services and activities involved in operating and distributing electricity to customers safely and reliably in accordance with the National Electricity Law, National Electricity Rules and jurisdictional requirements as a participant in the NEM and holder of a NSW distribution operator's licence. For example, this includes planning, designing, constructing, augmenting, maintaining, repairing, managing and operating the network and network demand for distributor purposes.</p> <p>Common distribution services involves, but is not limited to, the following activities:</p> <ul style="list-style-type: none"> • regulatory and pricing planning • demand management planning • management of environmental issues • asset relocations (not at customer's request) • vegetation management • works to fix damage to the network (including emergency recoverable works) or supporting another distributor during an 	Standard control	Standard control

¹⁹³ Per Utilities Commission (NT), *2014 Network Price Determination, Final determination, (Part A Statement of reasons and Part B Pricing Determination)*, February 2017. See: <http://www.utilicom.nt.gov.au/AboutTheCommission/consultations/2014/Pages/default.aspx>.

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
	<p>emergency event.</p> <ul style="list-style-type: none"> dial before you dig services external stakeholder management call centres, enquiries and billing performance monitoring. 		

Ancillary services

Design related services	<p>Activities includes:</p> <ul style="list-style-type: none"> processing preliminary enquiries requiring site specific or written responses provision of design information, design rechecking services in relation to connection and relocation works provided contestably. specialist services where the design is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets 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)
Access permits and oversight	<p>Activities include:</p> <ul style="list-style-type: none"> 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. 	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
	<ul style="list-style-type: none"> • A distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space. • A distributor providing access to switch rooms, substations and the like to a non-LNSP party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas. 		
Notices of arrangement	Work of an administrative nature performed by a distributor 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.	Alternative control	Alternative control (specific monopoly service)
Property services	<p>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.</p> <p>Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.</p>	Alternative control	Alternative control (specific monopoly service)
Site establishment services	Site establishment services, 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.	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
Networks safety services	Includes provision of traffic control services by the distributor where required, fitting of tiger tails, high load escort, night watch (private security and flood lighting services).	N/A	Alternative control (potentially contestable)
Customer vegetation defect works	Work involved in managing and resolving pre-summer bush fire inspection customer vegetation defects where the customer has failed to do so.	N/A	Alternative control (specific monopoly service)
Network tariff change request	When a retailer's customer or retailer requests an alteration to an existing network tariff (for example, a change from a Block Tariff to a Time of Use tariff), the distributors conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria. The distributors also process changes in their IT systems to reflect the tariff change.	Alternative control	Alternative control (specific monopoly service)
Recovery of debt collection costs - dishonoured transactions	The incurrence of costs, including bank fees by a distributor resulting from the dishonour of a customer's cheques tendered in payment of network related services.	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 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.	Alternative control	Alternative control (specific monopoly service)
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)

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
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)
Metering services			
Type 1 to 6 metering services	Type 1 to 6 meters and supporting services.	Standard control	Alternative control
Type 5 and 6 metering provision (before 1 July 2019)	Distributors may recover the capital cost of type 5 and 6 metering equipment installed before 1 July 2019. ¹⁹⁴	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
Meter reading and testing	Meter reading and testing services include: <ul style="list-style-type: none"> • 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 • Meter test (for type 5 and 6 meter) 	Alternative control	Alternative control (specific monopoly service)

¹⁹⁴ Subject to the NT Government finalising its metering policy.

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
	<ul style="list-style-type: none"> Types 5-7 non-standard meter data services Type 5 and 6 current transformer testing 		
Types 5 and 6 meter reading, maintenance and data services	Meter maintenance covers works to inspect, test, maintain, repair and replace 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)
Emergency maintenance of failed metering equipment not owned by the network	The distributor is called out by the customer 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.	Alternative control	Alternative control (specific monopoly service)
Meter recovery - type 5 and 6 current transformer metering	At the request of the customer or their agent to remove a type 5 or 6 current transformer meter where a permanent disconnection has been requested.	N/A	Alternative control (specific monopoly service)
Distributor arranged outage for purposes of replacing metering	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)
Site alteration service	Site alteration services updating and maintaining national metering identifier (NMI) and associated data in market systems.	N/A	Alternative control (specific monopoly service)
NMI extinction fee	At the request of the customer or their agent processing a request for permanent disconnection and the extinction of a NMI in market	N/A	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
	systems		
Correction of metering and market billing data	Confirming or correcting metering or network billing information in market B2B or network billing systems, due to insufficient or incorrect information received from retailers or metering providers.	N/A	Alternative control (specific monopoly service)
Connection services			
Connection services include premises connection services, extensions and network augmentation.	<p>Premises connection services includes any additions or upgrades to the connection assets located on the customer's premises (Note: excludes all metering services).</p> <p>Extensions include 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.</p> <p>Augmentations include any shared network enlargement/enhancement undertaken by a distributor which is not an extension.</p>	Standard control	Standard control
Registered participant support services	Services and information provided by the distributor and proposed market participants associated with connection arrangements and agreements made under Chapter 5 of the NER.	N/A	Alternative control (specific monopoly service)
Site inspection	Site inspection services in order to determine the nature of the connection service sought by the connection applicant.	N/A	Alternative control (specific monopoly service)
Facilitation of generator connection and operation on the network	Includes connection/disconnection of generator to distributor's assets and any ongoing requirements to facilitate its operation.	N/A	Alternative control (potentially contestable)

Service group/Activities included	Further description (if any)	Current Classification 2014–19 ¹⁹³	Proposed classification 2019–24
Reconnections/Disconnections	<p>Disconnection and/or reconnection services (some provided in accordance with the National Energy Retail Rules). For example:</p> <ul style="list-style-type: none"> • Disconnection visit (site visit only) • Disconnection visit (disconnection completed - technical) • Pillar box/pole top disconnection - completed • Reconnection/disconnection outside of business hours • Vacant property - site visit • Shared service fuse replacement • Rectification of illegal connections • Temporary connections • Remove or reposition connection • Single phase to three phase 	Alternative control	Alternative control (specific monopoly service)
Unregulated distribution services			
Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental etc.).	N/A	Unclassified
Contestable metering support roles	Includes metering coordinator, metering data provider and metering provider for meters installed or replaced after 1 December 2017.	N/A	Unclassified

