Preliminary framework and approach

TasNetworks electricity transmission and distribution Regulatory control period commencing 1 July 2019

March 2017

AUSTRALIAN ENERGY REGULATOR

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

Contents

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
CPI-X	consumer price index minus X
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
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
next regulatory control period	1 July 2019 to 30 June 2024
NUoS	network use of system

Shortened Form	Extended Form
opex	operating expenditure
RAB	regulatory asset base
ROLR	retailer of last resort
STPIS	service target performance incentive scheme

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: TasNetworksDistribution2019@aer.gov.au

Alternatively, submissions can be mailed to:

Mr Chris Pattas

General Manager, Networks

Australian Energy Regulator

GPO Box 520

Melbourne VIC 3000

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 Networks Branch of the AER on (03) 9290 1444.

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).

TasNetworks is the sole operator of the monopoly electricity transmission and distribution networks in Tasmania. The networks contain the towers, poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and business. TasNetworks designs, constructs, operates and maintains the distribution network for Tasmanian electricity consumers.

We make regulatory decisions on the revenue that TasNetworks can recover from its customers. We determine its revenue by an assessment of its efficient costs and forecasts. Our assessment is based on a regulatory proposals submitted by the network business in advance of a regulatory control period, in this case beginning 1 July 2019. The regulatory proposal sets out TasNetworks' view on its expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

The regulatory framework we administer is based on an incentive regime. We set a network business' allowed revenue for a period (typically five years) based on the best available information, rigorous assessment and consideration of consumers' views. A 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 services in Tasmania. 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 distribution 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 businesses prepare regulatory proposals.

Five years ago, we published an F&A for TasNetworks' electricity transmission network business[1] for the 2014–19 regulatory control period. Two years ago we published an F&A for TasNetworks' electricity distribution network business for the 2017–19 regulatory control period.[2] The short regulatory control period for TasNetworks' distribution network was to align its regulatory schedule with TasNetworks' transmission network. For the 2019−24 regulatory control period we will make determinations for TasNetworks' distribution and

1 Previously known as Transend.

2 Previously known as Aurora Energy.

transmission networks concurrently. This will minimise administrative costs incurred by TasNetworks and ourselves.

We consider it prudent to review the current F&A papers for both TasNetworks' distribution and transmission networks. The new F&A will cover TasNetworks' merged transmission and distribution businesses in the one document to reflect TasNetworks' 'one business' approach.[3] Also, changes to the NER in November 2012 introduced new incentive schemes and allow us to adopt improved approaches to assessing expenditure forecast by the network service provider.[4] The Power of Choice reforms also introduced changes to metering contestability.[5] Further, we are currently developing a new demand management incentive scheme (DMIS)[6] and have recently published a national ring-fencing guideline.[7]

Following release of this Preliminary F&A we will consult with interested parties before issuing our final F&A by 31 July 2017. Table 1 summarises TasNetworks' determination process.

Table 1 TasNetworks determination process

Step	Date
AER publishes preliminary position F&A for TasNetworks	March 2017
AER to publish final F&A for TasNetworks	July 2017
TasNetworks to submit regulatory proposal to AER	January 2018
AER to publish Issues paper and hold public forum	Feb/March 2018*
Submission on regulatory proposal close	May 2018
AER to publish draft decision	September 2018
TasNetworks to submit revised regulatory proposal to AER	December 2018
Submissions on revised regulatory proposal and draft decision close	January 2019*

3 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 2.

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

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

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

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

Step	Date
AER to publish TasNetworks determination for regulatory control period	April 2019

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

Source: NER, chapters 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 TasNetworks' regulatory proposal
- how we will calculate depreciation of TasNetworks' regulatory asset bases
- how we will price transmission assets (dual function assets).

The Federal Court is currently considering appeals of a number of our previous determinations. The outcomes of these Federal Court reviews may affect our positions on the matters above. We will consider the implications of the Federal Court's reviews when the Federal Court hands down its judgement.

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 TasNetworks. 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.[8] 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.

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

Table 2 Classifications of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than 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 the provision of those services.	Distributors and customers are able to negotiate prices according to a framework established by the NER. We are available to arbitrate if necessary.
Unclassified service		Services that are not distribution services or services[9] that are contestable.	We have no role in regulating these services.

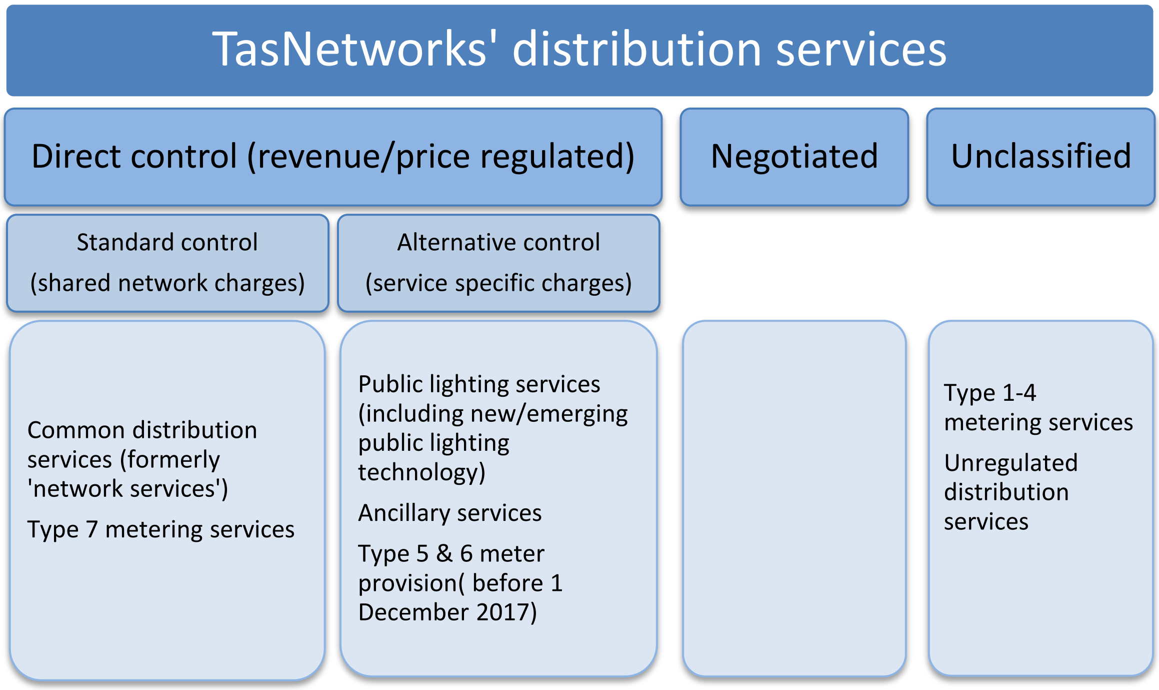
Source: AER

Our preliminary position is to change the classification of some of TasNetworks' distribution services for the 2019−24 regulatory control period. Specifically, we proposed to reclassify new/emerging public lighting technology from negotiated to alternative control. Otherwise we have clarified 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 classification for TasNetworks’ distribution services is set out in Figure 1 below.

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

Figure 1 AER proposed classification of TAS distribution services



Source: AER

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

Control mechanisms

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

Our preliminary position on the form of control mechanisms for TasNetworks' distribution business is:

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

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

For standard control services the NER mandates the basis of the control mechanism must be the prospective CPI-X form or some incentive-based variant.[13]

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

Incentive schemes

Incentive schemes encourage a network business to manage its networks in a safe, reliable manner that serves the long term interests of consumers. They provide a network business 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 TasNetworks:

- Distribution and Transmission Service Target Performance Incentive Schemes (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS)
- Demand Management Incentive Scheme (DMIS)

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

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline[14] is based on a reporting framework allowing us to compare the relative efficiencies of transmission and distribution networks. Our preliminary position is to apply the guideline, including its information requirements, to TasNetworks in the 2019−24 regulatory control period.

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

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

Depreciation

When we roll forward TasNetworks' transmission and distribution regulatory asset bases (RABs) 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 RABs as at 1 July 2024. In combination with our proposed application of the CESS this approach will maintain incentives for TasNetworks to pursue

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

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

capital expenditure efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

Our final F&A decision 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 Tasmanian customers, like the cost of other transmission assets. Distribution pricing rules recover costs from only the customers of a specific distribution network.

TasNetworks submitted that it does not operate dual function assets. As such we are not required to make a decision on the application of either transmission or distribution pricing rules.

1 Classification of distribution services

This chapter sets out our preliminary position on the classification of distribution services provided by TasNetworks in the 2019−24 regulatory control period. We don't consider the classification of TasNetworks' transmission services here because these are set in the National Electricity Rules. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services[15]
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

Our classification decisions therefore determine which services we will regulate and how distributors will recover the cost of providing those regulated services. We introduced our ring-fencing guideline for electricity distributors and our classification decisions will also settle ring-fencing obligations that will apply to TasNetworks for the 2019−24 regulatory control period.[16] For these reasons, we have closely reviewed the table of distribution services at appendix B.[17]

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.[18] 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.

15 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.

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

17 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 5.

18 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.

1.1 AER's preliminary position

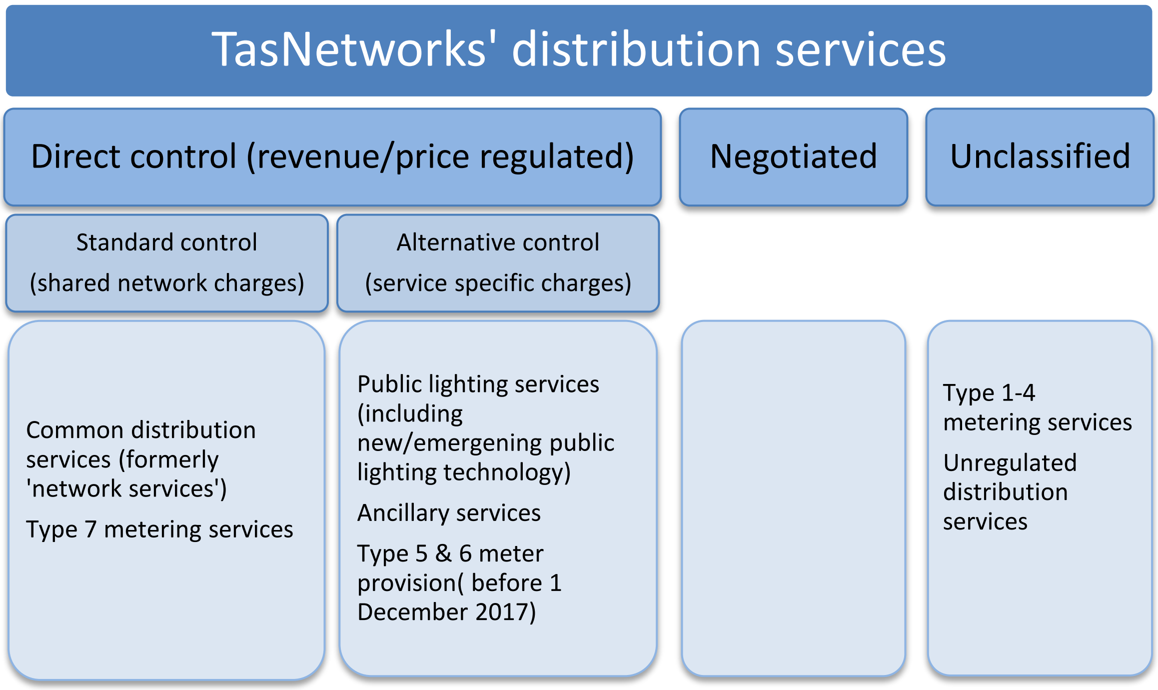
Overall, our preliminary position is to change the classification of some Tasmanian distribution services for the 2019−24 regulatory control period.

Our preliminary position is to group distribution services provided by TasNetworks as:

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

Figure 1.1 summarises our preliminary classification of Tasmanian distribution services. Our assessment approach and reasons follow.

Figure 1.1 AER proposed approach to classification of TAS distribution services



Source: AER

1.2 AER's assessment approach

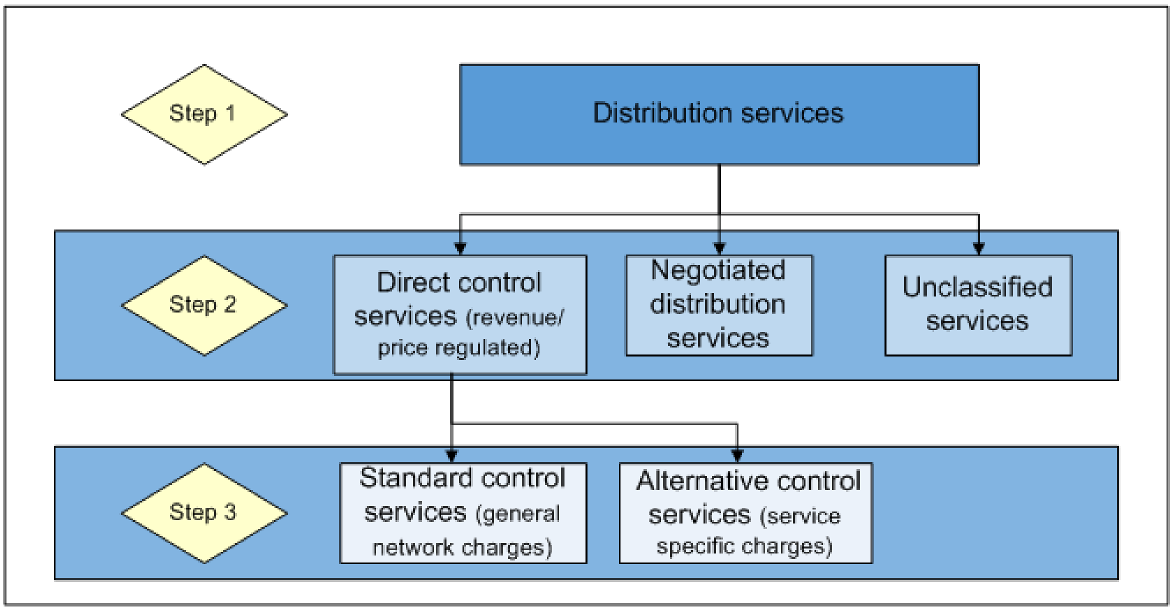
In conducting our assessment of distribution service classification, we commence on the basis that we:

- classify the service, rather than the asset – we can only decide on service classification if we understand what the service being provided is. That is, distribution service classification involves the classification of services distributors supply to customers rather than the classification of:
    - the assets used to provide such services;
    - the inputs/delivery methods distributors use to provide such services to
    - customers
    - services that consumers or other parties provide to distributors.
- classify distribution services in groups[19] – our general approach to service classification is to classify services in groupings rather than individually. This obviates the need to classify services one-by-one and instead defines a service cluster, that where a service is similar in nature it would require the same regulatory treatment. As a result, a new service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for ring-fencing purposes. This provides distributors with flexibility to alter the exact specification (but not the nature) of a service during a regulatory control period. Where we make a single classification for a group of services, it applies to each service in the group.
- 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.

[19] NER, cl. 6.2.1(b).

Figure 1.2 Distribution service classification process



Source: NER, chapter 6, part B.

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER define a distribution service as a service provided by means of, or in connection with, a distribution system.[20] 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'.[21]
- 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.[22] 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

20 NER, chapter 10, glossary.
21 NER, chapter 10, glossary.
22 NER, cl. 6.2.1(c); NEL, s. 2F.

of regulation applied to services and the desirability of consistency with the previous approach.[23]

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.[24] 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:[25]

- 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.[26]

Our classification decisions determine how distributors will recover the cost of providing services.[27] 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 ACS if it is either:

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

For services we classify as negotiated, distributors and customers will negotiate service provision and price under a framework established by the NER. Our role is to arbitrate disputes where distributors and prospective customers cannot agree. Two instruments support the negotiation process:

- Negotiating distribution service criteria—sets out the criteria distributors are to apply in negotiating the price, and terms and conditions, under which they supply distribution services. We will also apply the negotiating distribution service criteria in resolving disputes.

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23 NER, cl. 6.2.1(c).

24 NER, cl. 6.2.2(c).

25 NER, cl. 6.2.2(d).

26 NER, cll. 6.2.1(d) and 6.2.2(d).

27 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).

- 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. [28]

1.3 Reasons for AER's preliminary position

This section sets out our preliminary service classification and reasons for TasNetworks' 2019−24 regulatory control period for:

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

Appendix B contains a detailed table of our preliminary classification of Tasmanian distribution services.

1.3.1 Common distribution services

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

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

29 NER, Chapter 10 glossary.

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. TasNetworks hold an electricity distribution licence which is the only distribution license in place for Tasmania.[30] Under section 17 of the *Electricity Supply Industry Act* (TAS) 1995, a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so. These arrangements create a regulatory barrier, preventing third parties from providing common distribution services.[31] 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.[32] Our preliminary position is to retain the current standard control classification for common distribution services. There is no potential to develop competition in the market for common distribution services because of the barriers outlined above.[33] There would be no material effect on administrative costs for us, TasNetworks, users or potential users by continuing this classification.[34] We currently classify common distribution services (or 'network services') in Tasmania and all other NEM jurisdictions as standard control services.[35] Further, distributors provide common distribution services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[36]

Emergency recoverable works

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

Given that these services are provided in connection with a distribution system, we consider this a distribution service. However, we currently do not classify this service, treating it as an unregulated distribution service. This is because the cost of these works may be recovered 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.

30 Licences are issued by Office of the Tasmanian Energy Regulator.
31 NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).
32 NER, cl. 6.2.2(a).
33 NER, cl. 6.2.2(c)(1).
34 NER, cll. 6.2.2(c)(2), (3).
35 NER, cl. 6.2.2(c)(4).
36 NER, cl. 6.2.2(c)(5).

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.[37] 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. Going forward, we propose to adopt this approach across all NEM jurisdictions.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.[38] 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.[39]

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.[40]

The final rule alters who has overall responsibility for the provision of metering services by providing for the role and responsibilities of the Responsible Person to be performed by a new type of Registered Participant − a Metering Coordinator. Any person can become a Metering Coordinator subject to satisfying certain registration requirements.[41]

Retailers are required to appoint the Metering Coordinator for their retail customers, except where a party has appointed its own Metering Coordinator. The final rule also includes a

37 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

38 All connections to the network must have a metering installation (NER, cl. 7.3.1A(a)).

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

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

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

number of other features to support the competitive framework for the provision of metering services, including consumer protections.[42]

The new arrangements will commence on 1 December 2017 and have required changes to the NER and the National Electricity Retail Rules (NERR).[43] Consequently, our proposed classification of some metering services will also change for the 2019−24 regulatory control period.

Type 1 to 4 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. Type 1 to 4 meters are competitively available[44] and we do not currently regulate them in Tasmanian or in most other jurisdictions—they are unclassified and our preliminary position is for them to remain so.

Similarly, Pay-as-you-go (PAYG) metering services provided by Aurora Retail are distinct from the metering services provided by TasNetworks Distribution. PAYG metering services provided by Aurora Retail are unclassified and not regulated by us.

Type 5 and 6 metering services

TasNetworks is currently the monopoly provider of type 5 (interval) and 6 (accumulation) meters. However, from 1 December 2017 (and therefore before the commencement of the next regulatory control period on 1 July 2019), metering services across the National Energy Market will become contestable. Therefore, from 1 December 2017, households and other small customers who traditionally use these meter types may wish to change their metering provider and the type of meter they have. Further, TasNetworks will no longer be permitted to install or replace existing meters with type 5 or 6 meters. For this reason, type 5 and 6 metering installation and meter provision services become redundant services and are no longer permitted under the NER. Therefore our preliminary position is to not classify these services for the 2019−24 regulatory control period.

However, TasNetworks may still recover the capital cost of type 5 and 6 metering equipment installed before 1 December 2017 as an alternative control service.

Ancillary services − Metering

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

Some examples include:

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

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

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

- 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.[45]
- Distributor arranged outage for purposes of replacing meter − at the request of a retailer or metering coordinator, provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.[46]
- 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.[47]

A detailed list of these ancillary 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. TasNetworks is the monopoly provider of type 7 metering services in the Tasmania.[48]

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.[49] Currently, type 7 metering services in Tasmania are classified as alternative control services. However, a direct control and further, standard control service classification is clearly more appropriate for this monopoly service.[50] We are not departing from the current direct control service classification[51] and a standard control classification would satisfy the NER's desire for consistency in regulatory approach to type 7

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45 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 cl. 7.14.1A of the NER for the various categories of registration and metering installation types as detailed under cl. S7.4 of the NER.

46 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.

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

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

49 NER, 6.2.2(c)(1).

50 NER, cl. 6.2.1(d).

51 NER, cl. 6.2.1(d)(1).

metering services across NEM jurisdictions.[52] Our proposed change in classification would have no impact on the administrative costs on us, TasNetworks, users or potential users.[53]

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.[54]

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.[55] Some 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.

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach is to not classify these services.[56] 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.[57] 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.[58]

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

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

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

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 November 2015, pp. 127−131.

55 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. 129.

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

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

58 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.

party competitors (for a time).[59] 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.[60]

We appreciate that this is a new issue that is not entirely clear. We therefore welcome stakeholder comments.

1.3.3 Connection services

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

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

We currently classify TasNetworks' connection services, excluding augmentation, as direct control and further, as alternative control services. We have previously referred to these as 'basic connection services'. Our preliminary position is to continue this classification.

TasNetworks holds an electricity distribution licence which is the only distribution licence that is currently in place for Tasmania. Connection services involve work on, or in relation to, parts of TasNetworks' distribution network. We consider that, similar to common distribution services, there is a regulatory barrier preventing any party other than TasNetworks providing any connection services to its network.[61]

Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which TasNetworks provides these services. Furthermore, the scale of resources available to TasNetworks also likely prevents alternative providers from competitively providing connection services.[62] These factors support our view that TasNetworks possesses market power in providing connection services. Because of these barriers to competition from other service providers, we propose to continue classifying all connection services as direct control services.[63]

The nature of premises connection services and extensions is that in most instances, the customer requesting the service will benefit from the provision of that service. As such, the

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

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

61 NEL, s. 2F(a).

62 NEL, s. 2F(d).

63 NEL, s. 2F(a)(d).

costs are directly attributable to identifiable customers. We therefore propose to continue classifying these connection services as alternative control services.

We consider that retaining the current classification of premises connection services and extensions as alternative control services will have no material effect on administrative costs to us, TasNetworks, users or potential users. This is because classifying these services as alternative control services is consistent with the current regulatory approach.

Further, classifying premises connection services and extensions as alternative control services will facilitate introduction of competition, as being considered by the Tasmanian Government.[64]

We propose to classify connections requiring augmentation as direct control and standard control services. In most cases, if not all, augmentation of the network is a cost shared by all customers. We therefore consider that TasNetworks' possesses significant market power in providing augmentations to the shared network. A third party can only perform an augmentation at a distributor's discretion. This creates a monopoly, which requires a stringent regulatory approach. Additionally, we have classified connection services in other NEM jurisdictions as direct control services.[65]

We must further classify direct control services as standard or alternative control services.[66] Our proposed approach is to classify augmentations as standard control services. This is consistent with the current regulatory approach because:

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

For these reasons, we consider that it is clearly more appropriate to retain the current standard control service classification for augmentations.[67]

1.3.4 Ancillary services

64 Tasmanian Government Department of State Growth, *Tasmanian Energy Strategy – Restoring Tasmania's energy advantage*, May 2015, p. 23.

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

66 NER, cl. 6.2.2(c),

67 NER, cl. 6.2.2(d).

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

The above factors create a regulatory barrier preventing any party other than TasNetworks providing ancillary services in their respective distribution area.[68] Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that TasNetworks' possesses significant market power in providing ancillary services.[69]

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 TasNetworks provides these services to specific customers.[70] As such, the full cost of each ancillary service is directly attributable to an individual customer.[71] This results in costs that are more transparent for customers.

We adopt this view even though ancillary services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the administrative costs to us, the distributors, users or potential users.[72] This is because classifying ancillary services as alternative control services is consistent with the current approach.

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

1.3.5 Public lighting

TasNetworks operates and maintains the majority of public lighting systems throughout Tasmania. TasNetworks provides these services on behalf of local councils and government departments responsible for public lighting in Tasmania.

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

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68 NEL, s. 2F(a).

69 NEL, s. 2F.

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

71 NER, cl. 6.2.2(c)(5) - this includes a small number of identifiable customers.

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

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.[73]

We also propose to include new or emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that TasNetworks does not provide at the time of our distribution determination. However, emerging public lighting technology may become available during the 2019−24 regulatory control period. Currently emergency public lighting technology is classified as a negotiated distribution service.

We intend to classify public lighting (including new or emerging public lighting technology) as a direct control service and further, as an alternative control service. Our reasons follow.

We consider there to be significant barriers preventing third parties from providing public lighting services. While TasNetworks does not have a legislative monopoly over these services, a monopoly position exists. This is because TasNetworks owns the majority of public lighting assets. That is, other parties would need access to poles and easements for instance to hang their own public lighting assets.[74] However, TasNetworks owns and controls such supporting infrastructure. Therefore, similar to common distribution services, ownership of network assets restricts the operation, maintenance, alteration (including installing emergency public lighting technology) or relocation of public lighting services to TasNetworks. There is some limited scope for other parties to provide some public lighting services. For example, other parties may construct new public lights or perform works on independently owned public lighting assets.[75] Apart from these limited exceptions, we consider that a high barrier prevents third parties from entering this market. This limits competition in public lighting and results in TasNetworks' possessing significant market power.[76]

We currently regulate public lighting services in all NEM jurisdictions except the Australian Capital Territory and Northern Territory (where public lighting is government owned). We have classified some public lighting services in South Australia and Victoria as negotiated distribution services. However, the NER does not require us to classify similar services consistently between NEM jurisdictions.[77]

As direct control services, we must further classify public lighting services as either standard or alternative control services.[78] We intend to classify public lighting services as alternative control services for the following reasons:

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

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

75 That is, assets, like poles, not owned by TasNetworks. NEL, s. 2F(f).

76 NEL, s. 2F(d).

77 NER, cll. 6.2.1(c)(3) and 6.2.2(c)(3) and (4).

78 NER, cl. 6.2.2(c).

- classifying public lighting services as alternative control services provides scope for third parties and new entrants to provide public lighting services.[79]
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future, if a contestability regime is introduced. In the meantime, an alternative control classification supports the National Electricity Objective by ensuring distributors provide safe and reliable public lighting services to the community.[80]
- there would be no material effect on administrative costs to us, TasNetworks, users or potential users. This is because we are retaining the current classification.[81]
- TasNetworks can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.[82]
- under an alternative control service classification, as part of our distribution determination, we would set a cost-reflective price[83] for public lighting services based on information provided by the distributor. This would remove the need for councils to enter into negotiations with TasNetworks.
- based on submissions to us during the TasNetworks framework and approach for 2017−19, there does not appear to be an effective market for the majority of public lighting services in Tasmania and the ability of local councils to negotiate with TasNetworks appears quite uneven given their varying size and resources.[84]

For these reasons, we consider that public lighting services, including emerging public lighting technology, should be alternative control services.[85]

1.3.6 Unregulated distribution services

Unregulated distribution services is the term we us to describe distribution services which we have not classified as either direct control or negotiated services.[86] 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.[87] Our ring-fencing guideline interacts with a number of regulatory instruments, including our

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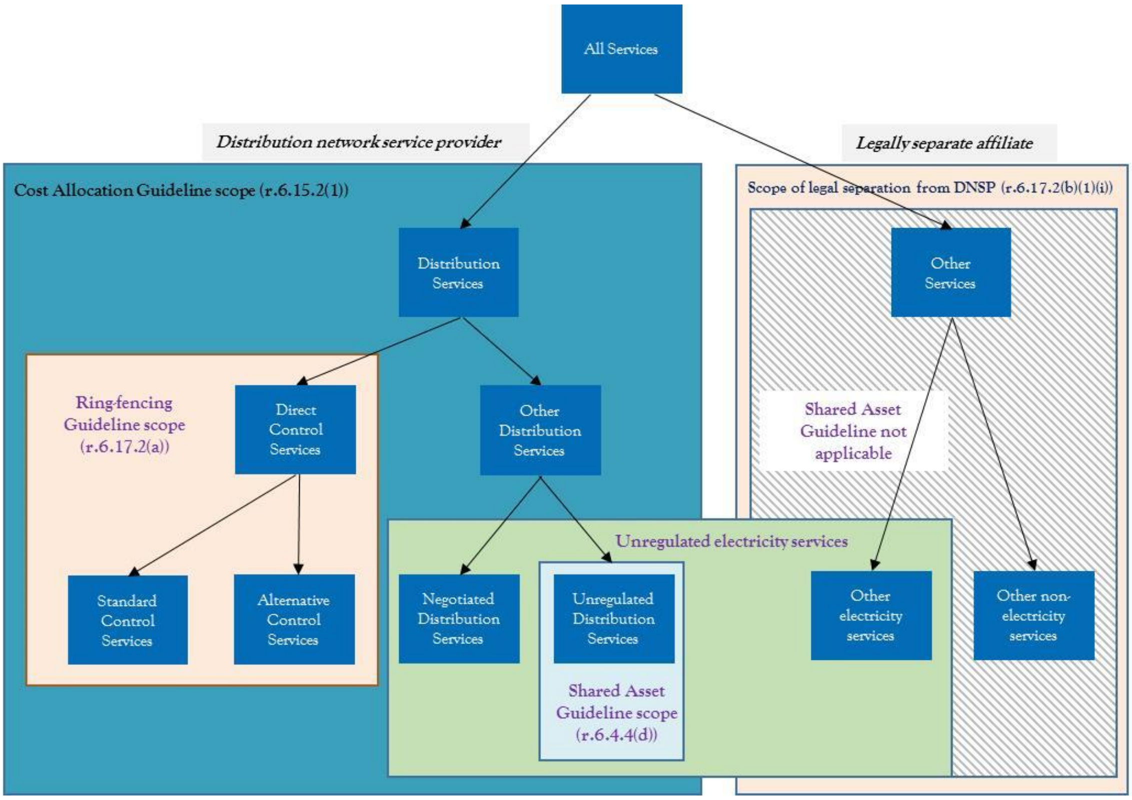
79 NER, cl. 6.2.2(c)(1).
80 NER, cl. 6.2.2(c)(1).
81 NER, cl. 6.2.2(c)(2).
82 NER, cl. 6.2.2(c)(5).
83 A formula would be developed as part of the control mechanism that would set the inputs to be included in quoting a fee.
84 AER, *Final framework and approach for TasNetworks 2017−19*, July 2015, p. 34.
85 NER, cl. 6.2.2(c)(3).
86 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.
87 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

service classification decisions. Specifically, our service classification decisions set ring-fencing obligations for each distributor for its next regulatory control period.[88] Under our ring-fencing guideline, any unregulated distribution service would be protected by functional and accounting separation. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services. Affiliated entities may provide other electricity services. For the purposes of this preliminary F&A we are not addressing interactions with other regulatory frameworks in detail as these are set out in the explanatory statement to the ring-fencing guideline.[89]

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

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

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

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 guideline[90] 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.

90 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.[91] This chapter sets out our preliminary positions, together with our reasons, on the form of control mechanisms to apply to TasNetworks' distribution 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.

This F&A paper does not address the form of control mechanism for TasNetworks' prescribed transmission services.[92] The NER requires a Transmission Network Service Provider's prescribed transmission services revenues to be subject to a revenue cap form of control.[93]

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

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.[94] 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.[95]

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control to TasNetworks' direct control services in the 2019–24 regulatory control period:

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

For standard control services, we note TasNetworks proposed the continuation of a revenue cap control mechanism.[96] TasNetworks did not comment on the control mechanism for alternative control services.

91 NER, cl. 6.2.5(a).
92 NER, cl. 6A.10.1A(b).
93 NER, cl. 6A.3.1.
94 NER, cl. 6.12.3(c).
95 NER, cl. 6.12.3(c1).
96 TasNetworks, *Letter to AER on framework and approach*, October 2016.

2.2 AER's assessment approach

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

- the form of the control mechanisms[97]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.[98]

The NER sets out the control mechanisms that may apply to both standard and alternative control services:[99]

- a schedule of fixed prices

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

- caps on the prices of individual services (price caps)[100]

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 overs and unders account, whereby any revenue over recovery (under recovery) is deducted from (added to) 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

97 NER, cl. 6.2.5(b).
98 NER, cl. 6.2.6(a).
99 NER, cl. 6.2.5(b).
100 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.

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 TasNetworks' standard control services, we have only considered the continuation of the revenue cap, or adoption of price caps or an average revenue cap. We have not considered the other forms of control mechanisms for standard control services based on our previous considerations that they are not superior to either an average revenue cap or a revenue cap in addressing the factors set out in clause 6.2.5(c) of the NER. We have also considered a price cap control mechanism as proposed by AGL.[101]

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.[102] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[103]

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.[104]

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 TasNetworks'

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

102 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.

103 NEL, s. 7.

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

standard control services would best address the factors set out in clause 6.2.5(c) of the NER.

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

2.2.1 Standard control services

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

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

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

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

The basis of the control mechanism for standard control services must be of the prospective CPI–X form or some incentive-based variant.[105]

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 must have regard to the factors in clause 6.2.5(d) of the NER:

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs for us, the distributor and users or potential users

[105] NER, cl. 6.2.6(a).

- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

We propose that another relevant factor is the provision of cost reflective prices. Efficient prices 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.[106] 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.[107]

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 TasNetworks' 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 no 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

106 NER, cl. 6.2.6(b).
107 NER, cl. 6.2.6(c).

In deciding on a control mechanism, the NER requires us to have regard to the need for efficient tariff structures.[108] 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.[109] 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:

- 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.[110] The tariff structure statement should show how a distributor applied the distribution pricing principles[111] to develop its tariff structures and the indicative price levels of tariffs for the coming five year regulatory control period. The network pricing

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

109 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.

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

111 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).

objective of the distribution pricing principles is the focus for a distributor when developing its network tariffs. The objective is that:[112]

> 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.[113]

Generally, a distributor is required to submit a tariff structure statement when submitting its regulatory proposal.[114] However, the NER permitted submission of the initial tariff structure statements outside the regulatory proposal process due to the timing of the rule changes.[115] 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 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.[116] We consider, where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor and users.

112 NER, cl. 6.18.5(a).
113 NER, cl. 6.12.3(k).
114 NER, cl. 6.8.2(a).
115 NER, cl. 11.76.2(a).
116 NER, cl. 6.2.5(c)(2).

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 TasNetworks' standard control services would best address clause 6.2.5(c)(2) of the NER. The continuation of a revenue cap would impose no additional administrative costs for us, TasNetworks or users.

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

2.3.3 Existing regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements applicable to the relevant service immediately before the commencement of the distribution determination.[117] We note maintaining a revenue cap control mechanism for TasNetworks' standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(3) of the NER than an alternative control mechanism.

2.3.4 Desirability of consistency between regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the desirability of consistency between regulatory arrangements for similar services both within and beyond the relevant jurisdiction.[118] We consider the continuation of a revenue cap control mechanism for TasNetworks' 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 TasNetworks revenue cap control mechanism 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.

117 NER, cl. 6.2.5(c)(3).
118 NER, cl. 6.2.5(c)(4).

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.[119]

AGL submitted that we review the control on TasNetworks' revenues in light of uncertainty around future network demand and utilisation.[120] AGL posited a price cap control would better align prudent expenditure and cost minimisation with maintaining network utilisation.

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

We also consider that 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.[121] The systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.[122] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[123]

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119 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.

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

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

122 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.

123 NEL, s. 7.

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.[124]

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.[125]

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.[126] The reverse happens with increasing demand. The true up of this under or over recovery of revenue is calculated in the unders and overs account.

Typically there is a two year lag 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).[127] The inclusion of this estimated year helps smooth year on year revenue and tariff adjustments because the

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124 NEL, s. 7.

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

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

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

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.[128] 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 TasNetworks' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling overs and unders 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.[129] Where prices are cost reflective, consumers and providers of demand side management face efficient incentives because they can take into account the cost of providing the service in decision making.

As stated above, AGL submitted that a price cap control mechanism be considered in light of uncertainty around network demand and utilisation.[130] 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.[131] 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.

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

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

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

131 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.

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.[132] 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.[133] Below is proposed formula to apply to TasNetworks' 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 TasNetworks' standard control services

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

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

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

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

where:

TAR_t is the total allowable revenue in year t.

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

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

t is the regulatory year.

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

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

133 NER, cl. 6.12.3(c1).

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

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

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

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

S_t is the s-factor for regulatory year t.[134] It will also incorporate any adjustments required due to the application of the STPIS in the 2017–19 regulatory control period consistent with the AER's STPIS.[135]

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[136] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

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

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

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

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134 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.

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

136 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.

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 TasNetworks' alternative control service.[137] We propose classifying the following services as alternative control services:

- type 5-7 metering services
- public lighting services
- ancillary network services (fee based and quoted services).

We note TasNetworks' alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2019–24 regulatory control period best meets the factors set out under clause 6.2.5(d) of the NER.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.[138] 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 network 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 a departure from the current price cap controls for TasNetworks alternative control services would not have a significant impact on the potential development of competition. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 discusses classification.

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

138 NER, cl. 6.2.6(c).

2.4.2 Administrative costs

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

2.4.3 Existing regulatory arrangements

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

2.4.4 Desirability of consistency between regulatory arrangements

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

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

2.4.5 Cost reflective prices

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

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for alternative control services.[139] 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.[140]

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

[139] NER, cl. 6.8.1(b)(2)(ii).
[140] NER, cl. 6.12.3(c1).

Figure 2.2 Preliminary positions price cap formula to be applied to TasNetworks' metering, public lighting and fee based services

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

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

Where:

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

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

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

t is the regulatory year.

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

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

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

X_t^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.

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

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

Figure 2.3 Preliminary positions price cap formula to be applied to TasNetworks' quoted services

$Price = Labour + Contractor\ Services + Materials$

Where:

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[142] 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.

142 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 TasNetworks for the 2019−24 regulatory control period. At a high level, our preliminary position is to apply the:

- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme.

3.1 Service target performance incentive scheme

We have separate service target performance incentive schemes for distribution and transmission network service providers. We consider these separately below.

3.1.1 Distribution STPIS

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

Our national distribution STPIS[143] 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 distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

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

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers[144] experiencing service below a predetermined level.[145]

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

144 Except where a jurisdictional electricity GSL requirement applies.

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

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

- the maximum revenue at risk under the STPIS
- how the distributor's network will be segmented
- the applicable parameters for the s-factor adjustment of annual revenue across customer service, reliability and quality of supply components
- performance targets for the applicable parameters in each network segment
- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates determining the relative importance of measured performance (against targets) across applicable parameters in each network segment.

TasNetworks can propose to vary the application of the STPIS in its regulatory proposal.[146] We can accept or reject the proposed variation in our determination. Each applicable year we will calculate TasNetworks' s-factor based on its service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.[147] A distributor proposing a delay must provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers.

Our national STPIS currently applies to TasNetworks which is subject to financial penalty or reward of ±5 per cent through an s-factor adjustment to revenue. GSLs are provided for through the Tasmanian Electricity Code's (TEC's) GSL scheme, so the GSL component of the AER's STPIS does not apply.

TasNetworks submitted that we should continue to apply the November 2009 distribution STPIS, excluding the GSL component.[148]

AER's preliminary position

Our preliminary position is to continue to apply the national STPIS to TasNetworks in the next regulatory control period. Our proposed approach to applying the national STPIS in the next regulatory control period will be to:

- set revenue at risk for TasNetworks within the range ±5 per cent.

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

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

148 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 6.

- segment the network according to Tasmanian Electricity Code (TEC) supply reliability categories (critical infrastructure, high density commercial, urban, high density rural and low density rural)
- set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index of SAIFI) and customer service (telephone answering) parameters
- set performance targets based on TasNetworks' average performance over the past five regulatory years
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the methodology and value of customer reliability (VCR) values as indicated in the AEMO's 2014 Value Of Customer Reliability Review final report.

We will not apply the GSL component if TasNetworks remains subject to a jurisdictional GSL scheme.

AER's assessment approach

The NER sets out certain requirements in relation to developing and implementing a STPIS.[149] These include:

Jurisdictional obligations

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

Benefits to consumers

Taking into account:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the willingness of the customer or end user to pay for improved performance in the delivery of services.
- Balanced incentives
- the past performance of the distribution network
- any other incentives available to the distributor under the NER or the relevant distribution determination

149 NER, cl. 6.6.2(b).

- the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
- the possible effects of the schemes on incentives for the implementation of non-network alternatives.

Our approach and reasons for developing the STPIS are contained in our final decision for the national distribution STPIS.[150]

Reasons for AER's preliminary position

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

Jurisdictional obligations

In Tasmania, the TEC sets out GSLs that apply to TasNetworks.[151] Our proposed approach to applying the STPIS in Tasmania is to not create duplication or compromise TasNetworks' 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 Tasmanian code remain in place. We will amend this position if the Tasmanian Government advises that these arrangements will cease to apply.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.[152]

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

- set the incentive rates for each reliability of supply parameter; and
- weight reliability of supply performance across different segments of the network.

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

151 OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007.

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

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.[153]

In September 2014 AEMO completed analysis of the VCR across the NEM.[154] This analysis will impact on our future development and application of the STPIS. We stated in our F&A paper for TasNetworks Distribution 2017−19 regulatory period, that we will apply a latest value for VCR through the distribution determination in calculating TasNetworks' incentive rates, because this approach better meets the STPIS objectives.[155] We consider that this approach is still appropriate.

Our preliminary position is to maintain revenue at risk for TasNetworks within the range ±5 per cent as we do not consider that a lower level would better meet the objectives of the STPIS.

TasNetworks has submitted that it will continue to consult with our customers on whether a penalty and reward mechanism of ±5 per cent is appropriate or another amount should apply.[156]

TasNetworks may propose an alternative VCR estimate and revenue at risk, supported by details of the calculation methodology, research and customer consultation, in its regulatory proposal. We would be interested in feedback on whether adopting a lower level of revenue at risk under the STPIS applied to TasNetworks would better meet the objectives of the scheme.

We seek stakeholder submissions on what are considered the appropriate VCR value and the appropriate level of revenue at risk applicable to TasNetworks under the STIPIS.

Balanced incentives

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

Defining performance targets

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

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

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

155 AER, *Final framework and approach for TasNetworks Distribution, for the Regulatory control period commencing 1 July 2017*, July 2015, p. 15.

156 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016..

The NER require us to consider past performance of the distributor's network in developing and implementing the STPIS.[157] Our preferred approach is to base performance targets on TasNetworks' average performance over the past five regulatory years.[158] Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in the final year of a regulatory control period to make future targets less onerous.

Distributors will only receive a financial reward after actual improvements are delivered to the customers. More importantly, a distributor can only retain its rewards if it can maintain the reliability improvements on an ongoing basis. Once an improvement is made, the benchmark performance targets will be tightened in future years. That is, the distributors' reliability targets for future years will be based on the level of performance that they have achieved to date. The reward for their improved performance is paid to the distributor (by customers) for five years. After which, customers will retain the benefit of the reliability improvement.

If the reliability levels should fall in the future, the distributor will receive penalties for not meeting the tightened targets—hence, the reward previously paid to the distributor will be returned to customers if the reliability levels fall.

Our national STPIS limits variability in penalties and rewards caused by circumstances outside the distributor's control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance.

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the NER or relevant distribution determination.[159] In Tasmania the STPIS will interact with our expenditure and demand management incentive schemes.

The efficiency benefit sharing scheme (EBSS) provides a distributor with an incentive to reduce operating costs. The STPIS counterbalances this incentive by discouraging cost efficiencies arising through reduced service performance for customers. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets.

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[160]

The capital expenditure sharing scheme (CESS) rewards a distributor if actual capex is lower than the approved forecast amount for the regulatory year. Since our performance

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

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

159 NER, cll 6.6.2(b)(3)(iv).

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

targets will reflect planned reliability improvements, any incentive a distributor may have to reduce capex by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

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

From time to time, we receive suggestion that outages caused by non-network solutions not delivering the contracted outputs to be excluded from the calculation of actual performance under STPIS to facilitate the take up of non-network solution projects. We consider that such arrangement will transfer the financial risk of non-network solution operators to customers.

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

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

3.1.2 Transmission STPIS

We create, administer and maintain the transmission STPIS in accordance with the requirements of the NER.[161] The STPIS provides incentives for each TNSP to provide greater transmission network reliability when network users place greatest value on reliability, and improve and maintain the reliability of the elements of the transmission network most important to determining spot prices.[162]

The transmission STPIS consists of three components:

- a service component, which has four main parameters and various sub-parameters which act as key indicators of network reliability
- a market impact component (MIC), which encourages TNSPs to minimise the impact of network outages on the dispatch of generation
- a network capability component, which encourages TNSPs to undertake low cost projects to promote efficient levels of network capability from existing assets when most needed, while maintaining adequate levels of reliability.

161 NER, cl. 6A.7.4(a).
162 NER, cl. 6A.7.4(b)(1).

Each year, the TNSP's maximum allowed revenue (MAR) is adjusted based on its performance against the STPIS parameters in the previous calendar year. The STPIS can result in a maximum revenue increment or decrement between one and five per cent of the annual MAR.[163]

Proposed approach

The version of the transmission STPIS in existence at the commencement of the regulatory control period will apply to TasNetworks. This is expected to be STPIS version 5 (October 2015). All three components (service, market impact and network capability) will apply.

The MAR that TasNetworks can earn in each regulatory year will be adjusted according to its performance against the values included in its transmission determination, as assessed by us in the annual compliance review process.[164]

Currently, TasNetworks report its transmission STPIS performance on a calendar year basis. Whereas, its distribution STPIS performance is reported on a financial year basis. TasNetworks suggested that we explore the possibility of aligning the reporting arrangements for transmission and distribution STPIS results so that both networks report performance on a financial year basis. It considers that a common reporting approach will assist all parties in better understanding performance across the combined networks.[165]

Since TasNetworks' proposal relates to the scheme design of STPIS. This issue will be considered when we review the scheme in due course. If the scheme is modified at a later stage in this regard, TasNetworks' reporting arrangements will be changed accordingly.

Reasons for proposed approach

We consider that the transmission STPIS will provide appropriate incentives for TasNetworks to (1) provide greater transmission network reliability; (2) improve and maintain the reliability of the elements of the transmission network to reduce the impact on wholesale market spot prices; and (3) undertake relevant low cost projects to promote efficient levels of network capability from existing assets.

Applying the STPIS in the next regulatory control period

In its revenue proposal, TasNetworks must:

- submit proposed values for the service component parameters.[166]

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163 NER, cl. 6A.7.4(b)(3).

164 STPIS, version 5, section 6.

165 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

166 STPIS, version 5, s. 3.2.

- submit data for its market impact component in accordance with Appendix C for the preceding seven regulatory years.[167] It must submit a proposed value for a performance target, unplanned outage event limit and dollar per dispatch interval incentive.[168]
- submit a network capability incentive parameter action plan.[169]
- We will accept TasNetworks' proposed parameter values for the service, market impact and network capability components if the proposed values comply with STPIS version 5 clauses 3.2, 4.2 and 5.2 respectively.[170]

Service component

The service component will apply to TasNetworks to provide an incentive to it to maintain and improve network availability and reliability.

In this component, TasNetworks can receive a revenue increment or decrement of up to 1.25 per cent of its MAR for the regulatory year.

Appendix A of the STPIS defines the service component parameters.[171] All service component parameters and sub-parameters apply to TasNetworks in STPIS version 5.[172]

We will assess whether TasNetworks' proposed performance targets, caps, floors and weightings comply with the parameter definitions, values and weightings set out in Section 3, Appendix A and Appendix E of the STPIS.

Our method of assessment of the parameter values is set out in section 3.2 of the STPIS. We may reject the proposed values where we are of the opinion that they are inconsistent with the objectives listed in clause 1.4 of the STPIS.[173]

Market impact component

The market impact component will be applied to TasNetworks to incentivise it to minimise the impact of its transmission outages that can affect NEM market outcomes.

In this component, TasNetworks will receive a financial incentive which falls within a range of minus one percent (penalty) and plus one per cent (reward) of its maximum allowed revenue.[174]

We will assess TasNetworks' proposed parameter values using the methodology set out in section 4, appendix C and appendix F of the STPIS.

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167 STPIS, version 5, s. 4.2(a).
168 STPIS, version 5, s. 4.2(b).
169 STPIS, version 5, s. 5.2(b).
170 STPIS, version 5, October 2015 .
171 STPIS, version 5, Appendix A.
172 STPIS, version 5, Appendix B.
173 STPIS, version 5, s. 3.2(l).
174 STPIS, version 5, s. 4.3.

Network capability component

- The network capability component will be applied to TasNetworks to incentivise it to identify and implement low cost one-off projects that will improve the capability of the transmission network at times most needed. AEMO will play a part in prioritising the projects to deliver best value for money for customers.
- In this component, TasNetworks will receive an annual allowance of up to a total of 1.5 per cent of MAR, but we may reduce the final payment (up to) minus 2 per cent of MAR, depending on the extent TasNetworks achieves its priority project improvement targets.[175]
- We will assess TasNetworks' network capability incentive parameter action plan in accordance with section 5.2 of the STPIS.

3.2 Efficiency benefit sharing scheme

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

TasNetworks proposed that the EBSS continues to apply to its transmission and distribution networks in the 2019–24 regulatory period.[176]

This section sets out our preliminary position and reasons on how we intend to apply the EBSS to TasNetworks transmission and distribution in the next regulatory control period.

3.2.1 AER's preliminary position

We propose applying the EBSS[177] to TasNetworks transmission and distribution for the 2019–24 regulatory control period.

Our transmission and distribution determinations for TasNetworks for the next regulatory control period will specify how we will apply the EBSS.

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing between a network service provider and network users of opex efficiency gains and efficiency losses.[178] We must also have regard to the following factors in developing and implementing the EBSS:[179]

175 STPIS, version 5,s.l 5.3(b).

176 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

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

178 NER, cll. 6.5.8(a) and 6A.6.5(a).

179 NER, cll. 6.5.8(c) and 6A.6.5(b).

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

3.2.3 Reasons for AER's preliminary position

The EBSS applies to TasNetworks transmission in the 2014–19 period and to TasNetworks distribution in the 2017−19 regulatory control period.[180]

The EBSS specifies the criteria for adjustments and exclusions under the scheme,[181] how we will determine the carryover period and how we will calculate the carryover amounts.[182]

In this section we set out why we propose to apply the EBSS to TasNetworks in the next regulatory control period.

The EBSS must provide for a fair sharing of efficiency gains and losses.[183] Under the scheme the network service provider and consumers receive a benefit where a network service provider 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 network service providers for efficiency gains and losses respectively.[184] The network service provider retains any efficiency gains or losses it makes for the length of the carryover period through the ex-ante opex allowance and the carryover payments it receives. In this way, the EBSS provides a continuous incentive for the network service provider to achieve opex efficiencies. This is regardless of the year in which it makes the gain or loss.[185]

This continuous incentive to improve efficiency encourages efficient and timely opex throughout the regulatory control period, and reduces the incentive for a network service provider to inflate opex in the expected base year. This provides an incentive for network

180 AER, *Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013.

181 We will no longer allow for specific exclusions such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth. We may also exclude categories of opex not forecast using a single year revealed cost approach from the scheme on an ex post basis if doing so better achieves the requirements of the NER.

182 AER, *Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013.

183 NER, cll. 6.5.8(a) and 6A.6.5(a).

184 NER, cl. 6.5.8(c)(3) and 6.5.8(a) and cl. 6A.6.5(b(2)).

185 NER, cll. 6.5.8(c)(2) and 6A.6.5(b).

service providers 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 network service providers and consumers.[186] 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 network service providers and consumers. This means for a one dollar efficiency saving in opex the network service provider 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.[187]

In implementing the EBSS we must also have regard to any incentives network service providers may have to capitalise expenditure.[188] Where opex incentives are balanced with capex incentives, a network service provider 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. We discuss the CESS further in section 3.33.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives.[189]

Expenditure on non-network alternatives generally takes the form of opex rather than capex. Successful non-network alternatives should result in the network service provider 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 network service provider 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 network service provider will receive a net reward for implementing the non-network alternative.[190] 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 a network service

186 NER, cll. 6.5.8(c)(1) and 6A.6.5(a).

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

188 NER, cll. 6.5.8(c)(4) and 6A.6.5(b)(3).

189 NER, cll. 6.5.8(c)(5) and 6A.6.5(b)(4).

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

provider may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.[191]

3.3 Capital expenditure sharing scheme

The CESS provides incentives to network service providers to undertake efficient capex by further rewarding efficiency gains and penalising efficiency losses. Consumers benefit from improved efficiency through lower network prices in the future. This section sets out our preliminary position and reasons for how we intend to apply version 1 of the CESS to TasNetworks distribution and transmission in the next regulatory control period.[192]

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend amount should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts.[193] We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added to or subtracted from the distributor's regulated revenue as a separate building block in the next regulatory control period.

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

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,[194] to TasNetworks in the 2019−24 regulatory control period.

191 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.

192 The distribution and transmission CESS are substantively the same, except that there is an exclusion from the transmission CESS for projects linked to the network capability incentive parameter action plan.

193 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.

194 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 network service provider, and the nature and details of any CESS to apply to a network service provider, we must:[195]

- make that decision in a manner that contributes to the capex incentive objective set out in the NER[196]
- consider the CESS principles,[197] capex objectives,[198] 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

TasNetworks proposed that the CESS continues to apply to its transmission and distribution networks in the 2019–24 regulatory period.[199]

TasNetworks is currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.[200] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[201] We are also proposing to apply forecast depreciation, which we discuss further in chapter 5.

In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the EBSS, STPIS, and DMIS—which TasNetworks will be subject to in the next regulatory control period.

For capex, the sharing any underspend and overspend amounts happens at the end of each regulatory control period when we update a network service providers' RAB to include new capex. If a network service provider 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.

195 NER, cll. 6.5.8A(e), 6A.6.5A(e).

196 NER, cll. 6.4A(a) and 6A.5; the capex criteria are set out in cll. 6.5.7(c) and 6A.6.7 of the NER.

197 NER, cll. 6.5.8A(c), 6A.6.5A(c).

198 NER, cll. 6.5.7(a), 6A.6.7(a).

199 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

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

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

Without a CESS the incentive for a network service provider to spend less than its forecast capex declines throughout the period.[202] Because of this a network service provider may choose to spend capex earlier, or spend on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

With the CESS a network service provider faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide a distributor with an ex ante incentive to spend only efficient capex. A network service provider that makes an efficiency gain will be rewarded through the CESS. Conversely, a network service provider that makes an efficiency loss will be penalised through the CESS. In this way, a network service provider 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 network service provider.

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

3.4 Demand management incentive scheme and innovation allowance mechanism

This section sets out our preliminary approach and reasons for applying our new demand management incentive scheme (DMIS) and demand management allowance mechanism (DMIA) to TasNetworks in the 2019−24 regulatory control period.

We apply a DMIS in our distribution determination for the current regulatory control period.[203] .

Our current DMIS consists of two parts. The first is the demand management innovation allowance (DMIA) which is incorporated into TasNetworks' revenue allowance for each year of the regulatory control period. TasNetworks prepares an annual report on their expenditure under the DMIA[204] in the previous year, which we then assess against specific criteria. The second element is a forgone revenue component, which allows a DNSP to recover forgone revenues that are directly attributable to a non-tariff demand management project or program approved under the DMIA. Compensation for foregone revenue is not applied where a distributor is subject to a revenue cap rather than a price cap.

Currently only the DMIA (Part A of the scheme) applies to TasNetworks because in the current regulatory control period it is subject to a revenue cap form of control. As a revenue

202 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.

203 NER, version 52, cl. 6.6.3 (a).

204 The DMIA excludes the costs of demand management initiatives approved in our determination for the 2012–17 period.

cap is expected to apply in the next regulatory control period, compensation for foregone revenue will not be relevant to TasNetworks in the next regulatory control period.

A recent rule change by the AEMC[205] has affected the NER requirements regarding the application of a demand management scheme. On 20 August 2015, the AEMC published its Demand Management Incentive Scheme Rule Determination as well as its accompanying Rule changes setting out amendments to establish the proposed demand management scheme. 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 network businesses with an incentive to encourage efficient demand management, both in implementing commercially viable demand management initiatives and in conducting research and development.

Under the new Rule, the objective of the DMIS/DMIA is to provide network businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The objective under the version of the NER applicable to the current regulatory control period 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 for the previous demand management scheme under the rule change.

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

We are currently developing a new scheme and allowance mechanism, and in January 2017 published a DMIS/DMIA Consultation paper.[206] We will continue the process of consultation, including with TasNetworks, for developing the DMIS and DMIS. 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 developed consequent to the rule change in August 2015 to TasNetworks in the next regulatory control period.[207] That is, in the 2019 distribution determination for TasNetworks we will apply our new DMIS and DMIA currently being developed under a separate process, as noted above.

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

206 AER, Consultation Paper- Demand management incentive scheme and innovation allowance mechanism, January 2017

207 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

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 TasNetworks.[208] These are:

DMIS Objective

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

Benefits to consumers

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

Balanced incentives

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

3.4.3 Reasons for AER's preliminary position on DMIS

This section outlines the reasons for our preliminary position to apply the DMIS to TasNetworks 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

208 NER, cl. 6.6.3(c).

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.[209] 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 mechanism is being considered in developing a scheme that would contribute to the achievement of the DMIS objective.[210] The mechanisms are discussed in our DMIS review Consultation Paper.

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 nett cost savings to retail customers[211]. The NER recognise that these nett cost savings to retail customers could be via the nett economic benefits delivered from implementing relevant non-network options[212] 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

209 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.

210 NER, cl. 6.6.3(c)(1).

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

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

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 network businesses 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 DMIS for TasNetworks.[213] These are:

DMIS Objective

- The DMIA should provide TasNetworks 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 DMIS 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.

[213] NER, cl. 6.6.3A(c).

3.4.5 Reasons for AER's preliminary position on DMIA

This section outlines the reasons for our preliminary position to apply the DMIS to TasNetworks 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 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 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 DMIS 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 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 DMIS will be designed so only funding is supplied which is not available from any another source, including under a relevant distribution determination, and this will form an assessment criteria for projects.

The design of the 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 forecast assessment guideline (the EFA guideline)[214] including the information requirements applicable to TasNetworks for the 2019−24 regulatory control period. We propose applying the guideline as it sets out our expenditure forecast 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 forecast expenditure, 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 TasNetworks to advise us by 30 November 2017 of the methodology it proposes to use to prepare its forecasts.[215] In the F&A we must advise whether we will deviate from the EFA guideline.[216] This will provide TasNetworks 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 TasNetworks, 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.[217]

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 EFA guideline is flexible and recognises that we may employ a range of different estimating techniques to assess an expenditure forecast.

214 We were required to develop the EFA guideline under clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4 of the NER. We published the guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

215 NER, cl.6.8.1A(b)(1), 6A.10.1B(b)(1), 11.60.3(c) and 11.58.4(n).

216 NER, cl. 6.8.1(b)(2)(viii) and 6A.10.1A(b)(5).

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

TasNetworks has raised concerns regarding our benchmarking methodology and approach, which is subject to judicial review currently.[218] We welcome TasNetworks' and stakeholders' submissions to the preliminary F&A in which they can raise their concerns with the application of the current EFA guideline.

[218] As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 8.

5 Depreciation

As part of the process of rolling forward a network service provider'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 TasNetworks' RAB is rolled forward to the commencement of the 2024–29 regulatory control period. Our approach applies to both TasNetworks' transmission and distribution network businesses.

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 network service provider; 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 the network service provider 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.[219] 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 network service provider 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 network service provider 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 network service provider 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 network service

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

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

5.1 AER's preliminary position

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

5.2 AER's assessment approach

We must decide for our determination whether we will use actual or forecast depreciation to establish a network service provider's RAB at the commencement of the following regulatory control period.[220]

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.[221] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[222]

- 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 TasNetworks at the commencement of the 2024–29 regulatory control period. We note that TasNetworks is supportive of using the forecast depreciation approach.[223]

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.[224]

Our approach is to apply forecast depreciation except where:

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220 NER, cll. S6.2.2B and S6A.2.2B.

221 NER, cll. 6.4A(b)(3) and 6A.5A(b)(3).

222 NER, cll. S6.2.2B and S6A.2.2B.

223 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 8.

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

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

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

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

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

The opening RAB at the commencement of the 2019–24 regulatory control period will be established using forecast depreciation. This is consistent with our previous determinations that apply to TasNetworks' distribution network for the 2017–19 regulatory control period and transmission network for the 2014–19 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2024–29 regulatory control period therefore maintains the current approach. TasNetworks is currently subject to a CESS under its transmission and distribution determinations and we propose to continue to apply the CESS to TasNetworks in the 2019–24 regulatory control period. We discussed this in section 3.3.

For TasNetworks, 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.[225] Our ex post capex measures are set out in the capex incentives guideline. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

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

6 Dual function assets

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

TasNetworks does not currently own, control or operate any dual-function assets, nor did it own, control or operate any dual function assets at the time of the last determination. Therefore, our preliminary position is that we are not required to, and will not; make any determination under the NER regarding dual-function assets.[226]

[226] NER, cll. 6.8.1(b)(1)(ii) and 6.25(b).

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[227]

- 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.[228]
- 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)[229]
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[230]
- any other relevant factor.[231]

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227 NER, cl. 6.2.1(c).
228 NEL, s. 2F.
229 NER, cl. 6.2.1(c)(2).
230 NER, cl. 6.2.1(c)(3).
231 NER, cl. 6.2.1(c).

The NER specify additional requirements for services we have regulated before.[232] They are:

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

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[233]

- 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.[234]

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.

232 NER, cl. 6.2.1(d).
233 NER, cl. 6.2.2(c).
234 NER, cl. 6.2.2(c).

Appendix B: Preliminary classification of Tasmanian distribution services

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
Common distribution services			
Common distribution services (formerly 'network services')	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 Tasmanian jurisdictional requirements as a participant in the NEM and holder of a distribution operator's licence. For example, this includes planning, designing, constructing, augmenting, maintaining, managing and operating the network and network demand for distributor purposes. Common distribution services involves, but is not limited to, the following activities: • 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	Standard control	Standard control

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
	during an emergency event. • dial before you dig services • external stakeholder management • call centres, enquiries and billing • performance monitoring.		
Ancillary services			
Design related services	Activities includes: • 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	Activities include: • A distributor issuing access permits or clearances to work to a person authorised to work on or near distribution	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
	systems including high and low voltage. • A distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space. • A distributor providing access to switch rooms, substations and the like to a non-LNSP party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas.		
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	Property tenure services related to obtaining deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with connection or relocation. Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
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)
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), de-energising wires for safe approach (e.g. for tree pruning).	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 cheque tendered in payment of network related services.	Alternative control	Alternative control (specific monopoly service)
Services provided in relation to a	The distributors may be required to perform a number of services as a distributor when a ROLR event occurs. For	Alternative control	Alternative control

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
Retailer of Last Resort (ROLR) event	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.		(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)
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 1-4 metering services	Type 1 to 4 meters and supporting services are competitively available.[235]	Unclassified	Unclassified
Type 5 and 6 meter provision (before 1 December 2017)	Distributors may recover the capital cost of type 5 and 6 metering equipment installed before 1 December 2017.	Alternative control	Alternative control (specific monopoly service)
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional	Alternative control	Standard control

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

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
	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.		
Meter reading and testing	Meter reading and testing services include: • Special meter reading for type 5 and 6 meters and move in and move out metering reading (type 5 and 6 meters) • Type 5 meter final read on removed type 5 metering equipment • Meter test (for type 5 and 6 meter) • Types 5-7 non-standard meter data services • Type 5 and 6 current transformer testing	Alternative control	Alternative control (specific monopoly service)
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)

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
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 systems	N/A	Alternative control (specific monopoly service)
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			
Premises connection services and extensions	Premises connection services includes any additions or upgrades (including design and construction) to the connection assets located on the customer's premises (Note: excludes all metering services). Extension is an enhancement required to connect a power	Alternative control	Alternative control

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
	line or facility outside the present boundaries of the transmission or distribution network owned or operated by a Network Service Provider		
Augmentations	Any shared network enlargement/enhancement undertaken by a distributor which is not an extension	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)
Reconnections/Disconnections	Disconnection and/or reconnection services (some provided in accordance with the National Energy Retail Rules). For example: • 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	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description (if any)	Current Classification 2017−19	Proposed classification 2019−24
	• Shared service fuse replacement • Rectification of illegal connections • Temporary connections • Remove or reposition connection • Single phase to three phase		
Public lighting			
Public lighting	Provision, construction and maintenance of public lighting	Alternative control	Alternative control
New public lighting technology	Provision or construction of new/emerging public lighting technology services	Negotiated	Alternative control
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