



# **Final framework and approach**

**AusNet Services, CitiPower,  
Jemena, Powercor and United  
Energy**

**Regulatory control period  
commencing 1 January 2021**

January 2019

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## Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Allowance Mechanism, DMIAM	demand management innovation allowance mechanism
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
DMIS	demand management incentive scheme
distributor, DNSP	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ESCV	Essential Services Commission of Victoria
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 January 2021 to 31 December 2025
Opex	operating expenditure
RAB	regulatory asset base
STPIS	service target performance incentive scheme

## Overview

The Framework and Approach (F&A) is the first step in a two-year process to determine efficient prices for electricity distribution services in Victoria for the 2021 to 2025 regulatory control period. The F&A determines, amongst other things, which services we will regulate and the broad nature of the regulatory arrangements. This includes an assessment of services to be regulated (service classification) and how we will control the prices and/or revenues set for those services (form of control) as well as the application of incentive schemes. The F&A also facilitates early consultation with consumers and other stakeholders and assists electricity distribution businesses prepare regulatory proposals.

This F&A outlines changes we are proposing that will affect the regulated services offered by the Victorian distributors for the next regulatory period (2021-25). In our view, changes to the F&A are necessary to reflect rule changes and the development of new incentive schemes and regulatory guidelines that will apply to the Victorian distributors.

In particular, in late 2017, the Australian Energy Market Commission (AEMC) changed the National Electricity Rules (NER) to amend the framework we use to classify the distributors' electricity distribution services.<sup>1</sup> Because of this rule change, we published the Distribution Service Classification Guideline and Exempt Assets Guideline, shortly after the release of the preliminary F&A. We have applied these Guidelines in making the final F&A for Victorian distributors. As well, the F&A reflects recent amendments to the *National Electricity (Victoria) Act 2005* which apply Chapter 5A of the NER and the AER's connection charge guideline to Victorian distributors.

Further, we developed a new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM or Allowance Mechanism)<sup>2</sup> and implemented a NEM-wide Ring-fencing Guideline.<sup>3</sup> We have reflected these changes to the regulatory environment in this F&A. Conversely, Power of Choice reforms that introduced metering contestability to residential electricity consumers in other jurisdictions do not apply in Victoria.<sup>4</sup> In 2017, the Victorian Government deferred metering competition in Victoria through an Order-In-Council.<sup>5</sup> This means the approach to the classification of metering services remains unchanged from that of the existing determination.

Following release of the preliminary F&A, we held a public forum on 25 October 2018, to allow interested parties to raise issues prior to making submissions, which closed on 9 November 2018.

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<sup>1</sup> AEMC, *Final rule determination - National Electricity Amendment (Contestability of Energy Services) 2017*.

<sup>2</sup> See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>.

<sup>3</sup> AER, *Ring-fencing guideline electricity distribution*, Version 2. October 2017. See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017>.

<sup>4</sup> See: <http://www.aemc.gov.au/Major-Pages/Power-of-choice>.

<sup>5</sup> Victorian Government Order-In-Council, No. S 346, 12 October 2017.

We received ten submissions in response to our preliminary F&A, three of which canvassed issues that are not within scope of the F&A to address. Appendix C sets out these issues and our response to them.

Table 1 summarises our Victorian distribution determination process.

**Table 1 Victorian distribution determination process**

Step	Date
AER published preliminary F&A for Vic distributors	14 September 2018
Stakeholder forum	25 October 2018
Submissions on preliminary F&A for Vic distributors closed	9 November 2018
AER to publish final F&A for Vic distributors	31 January 2019
Vic distributors submit regulatory proposals to AER	31 July 2019
AER publishes issues paper and holds public forum	October 2019*
Submissions on regulatory proposal close	November 2019
AER to publish draft decisions	March 2020
AER to hold a predetermination conference	April 2020
Vic distributors to submit revised regulatory proposals to AER	June 2020
Submissions on revised regulatory proposals and draft decisions close	July 2020*
AER to publish distribution determinations for regulatory control period	31 October 2020

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

Source: NER, chapter 6.

## Background

We are 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 NER.

AusNet Services, CitiPower, Jemena, Powercor and United Energy are the licensed, regulated operators of Victoria's monopoly electricity distribution networks connected to the National Electricity Market (NEM). The distribution network comprises the poles, wires and transformers used for transporting electricity to homes and businesses. The Victorian distributors design, construct, operate, and maintain their distribution network for Victorian electricity consumers.

We make regulatory decisions on the revenues the Victorian distributors can recover from their customers. We determine Victorian distributors' revenue by an assessment of their efficient costs and forecasts. We base our assessment on their regulatory proposals, submitted by each of the Victorian distributors, in advance of their regulatory control period, in this case beginning 1 January 2021. Regulatory proposals set out the network businesses' forecasts of their expected costs for providing distribution services, the application of incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

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

This chapter provides an overview of our proposed approach on:

- classification of distribution services (which services we will regulate)
- incentives schemes for service quality, capital expenditure and operating expenditure and demand management
- expenditure forecasting tools to test the network businesses' regulatory proposals
- how we will calculate depreciation of the network businesses' regulatory asset bases

It also sets out our decisions on:

- control mechanisms (how we will determine prices for regulated services)
- how we will price transmission assets (dual function assets).

We summarise below our approach to each of the above matters. The following chapters set out detailed discussions of each matter.

## **Classification of distribution services**

We regulate distribution services provided by the Victorian distributors. Service classification determines which services will be regulated and we also must determine how prices will be controlled. We regulate services that are provided on a monopoly basis under a price or revenue cap or other mechanism to control the charges that a distributor can levy customers. Less prescriptive regulation is required where the prospect of competition exists. In some situations we may remove regulation altogether.

A distributor must provide unregulated distribution services through either a separate affiliate to the distributor or it must demonstrate functional separation from the distributor's direct control services,<sup>6</sup> in accordance with our Ring-fencing Guideline.<sup>7</sup> In broad terms, this

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<sup>6</sup> Functional separation may include physical separation of offices, staff separation, accounting separation and separate branding/avoiding cross-promotion. See AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, available at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017> and

means the distributor will continue to provide existing regulated distribution services, but all unregulated distribution services or new services that come into existence within a regulatory control period must be provided separately to the regulated network business, unless we approve a waiver as permitted under the Ring-fencing Guideline.

The AEMC made a rule change to the NER in December 2017, which applies to the Victorian electricity distributors for the 2021–25 regulatory control period.<sup>8</sup> Under these changes, we developed the Electricity Distribution Service Classification Guideline which became effective on 1 October 2018. The intention of the Guideline is to provide a baseline set of distribution services, service groupings and classifications to improve the clarity and transparency of how we classify services.<sup>9</sup> Distributors are able to propose alternative service classifications or service descriptions if it would better meet their operational or jurisdictional requirements. The rule change made it easier for us to change the classification of services regardless of how services have been historically classified. More specifically, the rule change removed the requirement for us not to alter service classification unless another classification is clearly more appropriate.<sup>10</sup> This mandatory requirement had previously constrained our ability to move away from the status quo when considering service classification.<sup>11</sup>

Table 2 provides an overview of the service classifications available to us for the purposes of economic regulation under the NER.

**Table 2 Classifications of distribution services**

Classification		Description	Regulatory treatment
<b>Direct control service</b>	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network.  Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that a distributor may earn for all standard control services.  All customers via their regular electricity bill share the costs associated with these services.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than only by the local distributor.	We set service specific prices to provide a reasonable opportunity to enable the distributor to recover the efficient cost of each service from customers using that

<sup>7</sup> <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016>.

<sup>8</sup> AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

<sup>9</sup> See <http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services>.

<sup>10</sup> See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines>.

<sup>11</sup> Formerly clause 6.2.1(d), now deleted.

<sup>11</sup> The rule change also requires us to develop and publish service classification guidelines by September 2018, which will provide further clarity and transparency around how we classify services. See NER, cl. 6.2.3A.

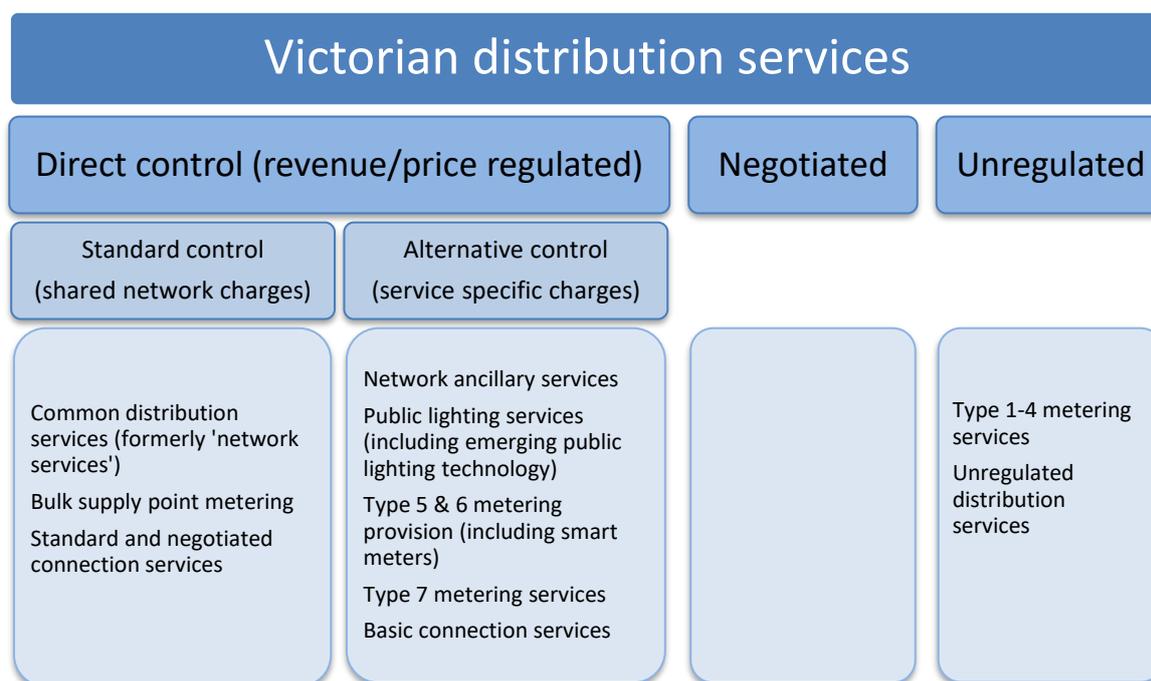
<b>Classification</b>	<b>Description</b>	<b>Regulatory treatment</b>
<b>Negotiated service</b>	Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing power to negotiate the provision of those services.	service. Distributors and customers are able to negotiate service and price according to a framework established by the NER. We are available to arbitrate if necessary.
<b>Unregulated distribution services</b>	We will not classify contestable distribution services.	We have no role in regulating these services.
<b>Non-distribution services</b>	Services that are not distribution services. <sup>12</sup>	We have no role in regulating these services.

Source: AER

In this F&A we have changed the classification of some Victorian distribution services for the 2021–25 regulatory control period. While we have retained existing service classifications for most services, we have clarified some service descriptions to better align with the services distributors provide and create greater consistency and predictability across jurisdictions as to how we classify distribution services. An overview of our proposed service classifications for the Victorian network businesses is set out in figure 1 below.

<sup>12</sup> The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system. NER, Chapter 10, glossary.

**Figure 1 AER proposed classification of Victorian distribution services**



Source: AER

Our final F&A decision on service classification is not binding for our determination on the Victorian network businesses' regulatory proposals. However, under the NER we may only change our classification approach in making the determination if a material change in circumstances justifies a departure from our final F&A.<sup>13</sup> Our Service Classification Guideline, which took effect on 1 October 2018, triggered some refinements to the service classifications set out in this final F&A (compared to the draft). In particular, this F&A adopts the typology of connection services set out the Guideline. In addition, distributors requested that a number of services listed within the baseline services list provided by the Guideline be included in their services lists.

### Form of control

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.<sup>14</sup> We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A, unless we consider there has been a material change in circumstances and we consider no form of control mechanism set out in the final F&A should apply to that distribution service.<sup>15</sup> In deciding control mechanism forms, we must select one or more from those listed in the NER.<sup>16</sup> These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

<sup>13</sup> NER, cl. 6.12.3(b).

<sup>14</sup> NER, cl. 6.2.5(a).

<sup>15</sup> NER, cl. 6.12.3(c).

<sup>16</sup> NER, cl. 6.2.5(b).

Our position on the form of control mechanisms for the Victorian network businesses is to retain the long-standing approaches of:

- Revenue cap — for services we classify as standard control services.
- Revenue cap — for types 5 and 6 (including smart meters) metering services we classify as alternative control services.
- Caps on the prices of individual services — for other services we classify as alternative control services.

For standard control services, the NER mandates that the basis of the control mechanism must be the prospective CPI–X form or some incentive-based variant.<sup>17</sup>

Our final F&A decision on the form of control is binding on the Victorian distributors and us for the 2021–25 regulatory determination.<sup>18</sup> We may only vary our proposed control mechanism formulas in making the determination in response to a material change in circumstances.<sup>19</sup> However, without affecting the content of a determination that has already been made, an F&A paper may be amended or replaced in accordance with the rules and with consultation.<sup>20</sup>

## Incentive schemes

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

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

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

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<sup>17</sup> 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.

<sup>18</sup> NER, cl. 6.8.1(b)(1)(i).

<sup>19</sup> NER, cl. 6.12.3(c)(1).

<sup>20</sup> NER, cl 6.8.1(a)(2), 6.8.1(c)(3).

## Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline<sup>21</sup> is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our proposed position is to apply the guideline, including its information requirements, to the Victorian network businesses in the 2021–25 regulatory control period.

Our Guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the Victorian distributors' regulatory proposals. We intend to apply the assessment/analytical tools set out in the Guideline and any other appropriate tools for assessing expenditure forecasts.<sup>22</sup>

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

## Depreciation

When we roll forward the Victorian network businesses' regulatory asset bases (RABs) for a regulatory control period we must adjust for depreciation.<sup>23</sup> Our position is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RABs as at 1 January 2026. In combination with our proposed application of the CESS, this approach will maintain incentives for the distributors to pursue capex efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

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

## Dual function assets

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

None of the Victorian distributors currently own, control or operate any dual function assets. This is because there is a framework in section 50 of the National Electricity Law for a 'declared transmission system', which has been adopted in Victoria.<sup>24</sup> Therefore, our decision is that we are not required to make any determination under the rules regarding dual function assets.<sup>25</sup>

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<sup>21</sup> AER, *Expenditure Forecast Assessment Guideline for Distribution*, November 2013.

<sup>22</sup> We are continuously improving the economic benchmarking techniques that are captured in our Guideline. This includes reviewing and refining our analysis of operating environment factors. See section 4 for more detail.

<sup>23</sup> For clarification, when we adjust for depreciation in relation to rolling forward the RAB, it is for standard control services only.

<sup>24</sup> NEL, s. 50.

<sup>25</sup> NER, cl. 6.8.1(b)(1)(ii), cl. 6.25(b).

## Consumer engagement<sup>26</sup>

With the industry undergoing a period of rapid transformation, which has enabled consumers to become more active participants in the market and to take greater control over their energy use, consumer engagement is becoming increasingly important in the development of proposals by network businesses. The increased focus on consumer engagement has led network businesses to commence engagement activities with consumers much earlier in the regulatory process than ever before. All distributors have already commenced consumer engagement processes.

- CitiPower, Powercor and United Energy<sup>27</sup> commenced its customer engagement program in early 2017 by conducting focus groups, interviews and surveys with more than 2,000 customers across their distribution areas. Through this, these distributors state that they have gained customer insights on energy behaviours, key energy priorities and expectations for the future, which fed into the first deliberative workshop, conducted in November 2017. This workshop included 50 key energy stakeholders from Victoria who deliberated on the most likely drivers of change and the possible scenarios for the future of the network. Through to December 2018, CitiPower, Powercor and United Energy have conducted research into what customers value the most about electricity supply and what services they would prefer to receive in the future. The research through 2018 included: three forums with 40 community opinion leaders in Melbourne, Geelong and Mildura.
- three deliberative workshops with 250 residential and small business customers
- 20 interviews with large customers
- 1,800 surveys of residential and small business customers
- A second network pricing forum with other Victorian distributors
- three Investment Options forums with 120 residential and small business customers
- on-going meetings with retailers and large commercial and industrial customers on future network options.

The qualitative and quantitative feedback from this wave of engagement has informed its Draft Proposals which the VIC distributors released for customer feedback in January 2019. CitiPower, Powercor and United Energy informed us that it expects to conduct in-depth engagement during 2019 with customers and stakeholders on the Draft Proposals, including 'deep dives' and other forums with customers and stakeholders.<sup>28</sup>

Jemena's engagement program commenced in mid-2017 with research to understand customer values and how to communicate effectively, complex electricity and regulatory concepts. Considering this feedback, in 2018 Jemena established a Peoples Panel of 43

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<sup>26</sup> Note: The detail in this section has been provided by the distributors. We will make comment on their consumer engagement during the reset process.

<sup>27</sup> Detail provided by CitiPower, Powercor and United Energy in response to a request by us to provide an update regarding the distributor's consumer engagement activities.

<sup>28</sup> Detail provided by CitiPower, Powercor and United Energy in response to a request by us to provide an update regarding the distributor's consumer engagement activities.

residential customers across its network area. Jemena stated that the Panel met over five sessions exploring key themes of affordability, reliability, pricing structures and the network of the future. Jemena stated that each session built on the previous, and provided the space to discuss and understand different views in the community, and to develop a consensus on the approach Jemena should take when preparing its proposal. To do this, the panel sought inputs from a broad selection of Jemena staff including its Executive team and experts across the energy industry. In August 2018, the Panel provided a set of recommendations, directly to Jemena's Board, to consider when preparing its regulatory proposal. Jemena submitted that it has also engaged one-on-one with large business customers and energy retailers, through to hand-delivered surveys for small business customers and focused forums with other stakeholders including Local Government Councils.<sup>29</sup>

Jemena stated that it would reconvene its Peoples Panel in March 2019 to deliberate on its draft regulatory proposal, and continue the conversation with other customer and stakeholder groups, including deep-dives. In particular, Jemena intends to collaborate with the other Victorian electricity businesses to finalise and consult on a draft tariff structures statement.<sup>30</sup>

AusNet Services is trialling the New Reg process, which was jointly developed by the AER, Energy Networks Australia and Energy Consumers Australia. The overall vision of the New Reg process is that energy consumers' priorities should drive network businesses' proposals and regulatory outcomes.<sup>31</sup>

The New Reg process established a Customer Forum that is tasked with the responsibility of being a credible counterparty in negotiations with a regulated business on elements of the regulated businesses regulatory proposal. The engagement between AusNet Services and the Customer Forum to continue into 2019, after we make our final decision on the F&A. We are not bound by the outcomes of the negotiations and we will assess AusNet Services' regulatory proposal as normal.

AusNet Services commenced the recruitment process for the Customer Forum in late 2017.<sup>32</sup> All Customer Forum members were engaged and the Forum commenced in March 2018. Over the first half of 2018, AusNet Services held monthly workshops with the Forum and consulted with us to agree the scope of the negotiations between the Customer Forum and AusNet Services and associate timeframes. In August 2018, AusNet Services commenced a process of negotiations with the Customer Forum on aspects of its regulatory proposal. These negotiations informed the draft regulatory proposal for public consultation, which was published by AusNet Services in January 2019 alongside an Interim Engagement Report. AusNet Services has sought stakeholder input on a range of issues before

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<sup>29</sup> Detail provided by Jemena in response to a request by us to provide an update regarding the distributor's consumer engagement activities.

<sup>30</sup> Detail provided by Jemena in response to a request by us to provide an update regarding the distributor's consumer engagement activities.

<sup>31</sup> AER, *Energy Consumers Australia, Energy Networks Australia, New Reg towards consumer centric energy network regulation, directions paper*, March 2018, p. 3.

<sup>32</sup> Detail provide by AusNet Services in response to a request by us to provide an update regarding the distributor's consumer engagement activities.

finalisation of the regulatory proposal.<sup>33</sup> Issues that are subject to further consultation include:

- the proposal for a small scale incentive scheme - and its design; and
- options to manage the increasing penetration of distributed energy resources.

Further information on the New Reg process is set out in detail in the directions paper,<sup>34</sup> AusNet Services' Early Engagement Plan,<sup>35</sup> and a memorandum of understanding between the AER, AusNet Services and the Chair of the Customer Forum, Tony Robinson.<sup>36</sup> More information about the New Reg process more broadly is available on the AER website.<sup>37</sup>

Key dates for the Customer Forum pre-proposal engagement process are as follows.

Event	Date
Customer Forum appointment, training and first round negotiation	March 2018 – November 2018
Advocates workshop	October 2018
Release draft regulatory proposal	January 2019
Release customer forum interim engagement report	January 2019
Consultation on draft proposal	January to May 2019
Assessment of feedback on draft regulatory proposal	May to June 2019
Final negotiation with the customer forum	May to June 2019

Source: AusNet Services.

In addition to the Customer Forum and associated New Reg process, AusNet Services has undertaken a concurrent stream of customer research activities, including in-depth stakeholder interviews, Community Forums, Focus Groups and customer surveys. AusNet Services formed a Customer Consultative Committee (CCC) in 2016 to act as a direct channel for external customer perspectives and inform decision making with AusNet Services.<sup>38</sup> The CCC has also been engaged on the Draft Proposal and has met with the Customer Forum.

<sup>33</sup> AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25*, p. 8

<sup>34</sup> AER, *Energy Consumers Australia, Energy Networks Australia, New Reg towards consumer centric energy network regulation, directions paper*, March 2018.

<sup>35</sup> AusNet Services, *Early Engagement Plan, EDPR 2021-2025 Customer Forum*.

<sup>36</sup> AusNet Services, AER, Tony Robinson, *Memorandum of Understanding between Australian Energy Regulator, AusNet Services, and Tony Robinson*.

<sup>37</sup> See <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-innovation>.

<sup>38</sup> See: <https://www.ausnetservices.com.au/Community/Customer-Consultative-Committee>.

In its request to replace the current F&A, AusNet Services requested that we acknowledge the Customer Forum process in the F&A and provide some high level guidance regarding how this will be incorporated into our approach to F&A matters including:

- the application of the Better Regulation Guidelines, such as the Expenditure Forecast Assessment Guideline,
- the way in which the incentive schemes are applied and the development of any small scale incentive schemes, and
- proposed new services and their classification.<sup>39</sup>

We expect that the Customer Forum process will contribute to the development of a regulatory proposal by AusNet Services that is better aligned with consumer interests. We will formally consider any inputs from the Customer Forum as part of the Draft Determination process, after AusNet Services has submitted its regulatory proposal. We are permitted to make changes to service classification in the Draft Determination and Final Determination if we consider that a material change in circumstances justifies departing from the classification set out in the final F&A paper. Any input from the Customer Forum on service classification issues following publication of the final F&A on 31 January 2019 would need to satisfy this requirement.<sup>40</sup>

In its submission to the preliminary F&A, the Consumer Challenge Sub-Panel (CCP17) applauded the focus the F&A is placing on consumer engagement. They also recognised that the distributors are approaching consumer engagement differently and this is as it should be because there is no "correct" or "best" methodology for the process. CCP17 suggested that this final F&A should go further than simply recognising the efforts of the distributors by providing some high-level objectives that consumer engagement should meet.<sup>41</sup> For example, it suggested this final F&A could "*specify the expectation that regulatory proposals identify and describe the consumer engagement that was applied and include commentary about the extent to which input from consumers has been heard and applied in the regulatory proposal*".<sup>42</sup>

While we agree with the underlying sentiment that regulatory proposals should reflect the consumer engagement activities of the regulated business, the purpose of the F&A is not to direct how businesses deliver the content of their regulatory proposals. One of the core objectives of the CCP is to advise us on the effectiveness of network businesses' engagement activities and whether their proposals reflect customer views.<sup>43</sup> Accordingly, we take into account the CCP's independent reports on each businesses' engagement activities and whether it considers that customer views have influenced a regulatory proposal.

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<sup>39</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 3–4.

<sup>40</sup> NER, cl. 6.12.3(b).

<sup>41</sup> CCP17, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 12 November 2018, p. 12.

<sup>42</sup> CCP17, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 12 November 2018, p. 12.

<sup>43</sup> See: <https://www.aer.gov.au/about-us/consumer-challenge-panel>

In its submission, Energy Consumers Australia (ECA), a peak body representing residential and small business energy consumers, expressed three high-level principles by which it assessed whether regulatory proposals have been prepared in the interests of consumers:

- The network business should be able to demonstrate that it has developed a deep understanding of the preferences of its consumers.
- The business should be able to talk about its longer-term strategy and business plans to provide a context for the five-year revenue proposal under consideration, including a long-term price path expectation.
- The business should be able to acknowledge the problems created by decisions made previously – comparatively less spending per se, is not enough. Consumers are looking for positive assurance that spending is designed to meet the NEO.<sup>44</sup>

According to the ECA, underpinning all successful revenue proposals is thoughtful, genuine consumer engagement that results in sustained cultural change throughout all aspects of the business.<sup>45</sup>

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<sup>44</sup> ECA, *Submission on the Victorian Preliminary Framework and Approach 2021-25* - 19 November 2018, p.5.

<sup>45</sup> ECA, *Submission on the Victorian Preliminary Framework and Approach 2021-25* - 19 November 2018, p.7.

# 1 Classification of distribution services

This chapter sets out our position on the classification of distribution services provided by the Victorian distributors in the 2021–25 regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services<sup>46</sup>
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

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

Our Electricity Distribution Ring-fencing Guideline, which came into effect in December 2016, has prompted distributors to review the classification of services that they provide. Our classification decisions settle the precise manner in which ring-fencing obligations will apply to each Victorian distributor for the 2021–25 regulatory control period.<sup>47</sup> In July 2016, the *National Electricity (Victoria) Act 2005* was amended so that chapter 5A of the NER and the AER's Connection Charge Guideline apply to Victorian distributors. For these reasons, we have closely reviewed the table of distribution services at appendix B.

The Australian Energy Market Commission (AEMC) recently made changes to the NER, following two rule change proposals from the Council of Australian Governments' Energy Council and the Australian Energy Council, on contestability of energy services.<sup>48</sup> Part of the new rule required us to develop a service classification guideline, which came into effect 1 October 2018. More specifically, the NER has removed the requirement for us to maintain a current service classification unless another classification is clearly more appropriate. Removing this provision provides an opportunity to improve clarity, and achieve greater consistency across jurisdictions as far as practicable. It also provides more predictability in how we might classify distribution services and sets out service descriptions that better align with the services being provided.

The Service Classification Guideline does not bind the AER. The intention of the Guideline is to provide a baseline set of distribution services, service groupings and classifications to improve the clarity and transparency of how we classify services.<sup>49</sup> Distributors are able to

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<sup>46</sup> 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.

<sup>47</sup> AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

<sup>48</sup> See <http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services>.

<sup>49</sup> See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines>.

propose alternative service classifications or service descriptions if it would better meet their operational or jurisdictional requirements. However, we are required to set out our reasons for any departure from the guideline to provide transparency to stakeholders in circumstances where our approach differs from that in the classification guideline.

In most cases, the classification of services carries over from the preliminary F&A, except where there are reasons to depart from that approach. This final F&A adopts much of the typology of the Service Classification Guideline, particularly in relation to connection services, but does not always coincide with the classification of those services from the Guideline. The classification of services for Victorian distributors departs from the Guideline to meet operational and jurisdictional requirements. We set out our reasons below.

## 1.1 AER's preliminary position

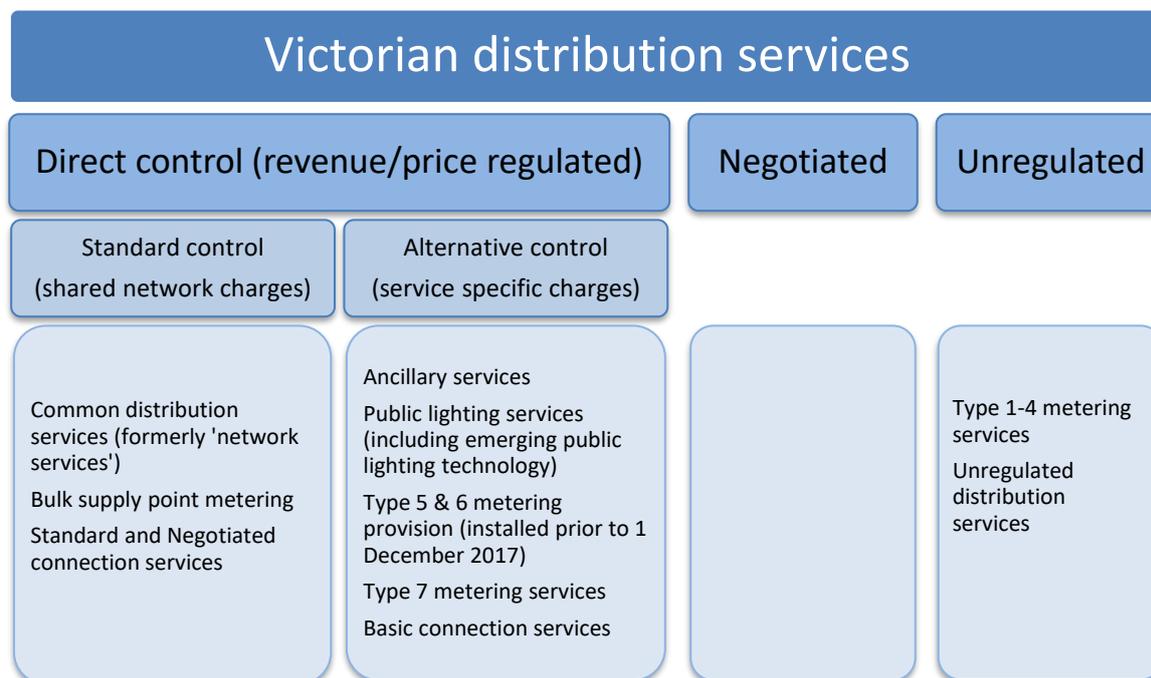
Overall, our position is to change the description and classification of some Victorian distribution services for the 2021–25 regulatory control period.

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

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

Figure 1.1 summarises our classification of the Victorian distribution services. Our assessment approach and reasons follow.

**Figure 1.1 AER proposed approach to classification of Victorian 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<sup>50</sup> – we can only decide on service classification by reference to the service that is being provided. That is, distribution service classification involves the classification of services distributors directly supply to customers. It does not involve the classification of:
  - the assets used to provide such services
  - the inputs/delivery methods distributors use to provide such services to customers, or
  - services that consumers or other parties provide to distributors.
- classify distribution services in groups<sup>51</sup> – our general preference in 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

<sup>50</sup> The AEMC's Contestability of energy services rule change, made in December 2017, introduced a requirement for the AER to regulate 'restricted assets'. The AER does not classify assets as restricted assets; rather, the term is defined in the NER. The AER has a role only in assessing applications for exemptions from the restricted assets provisions of the NER.

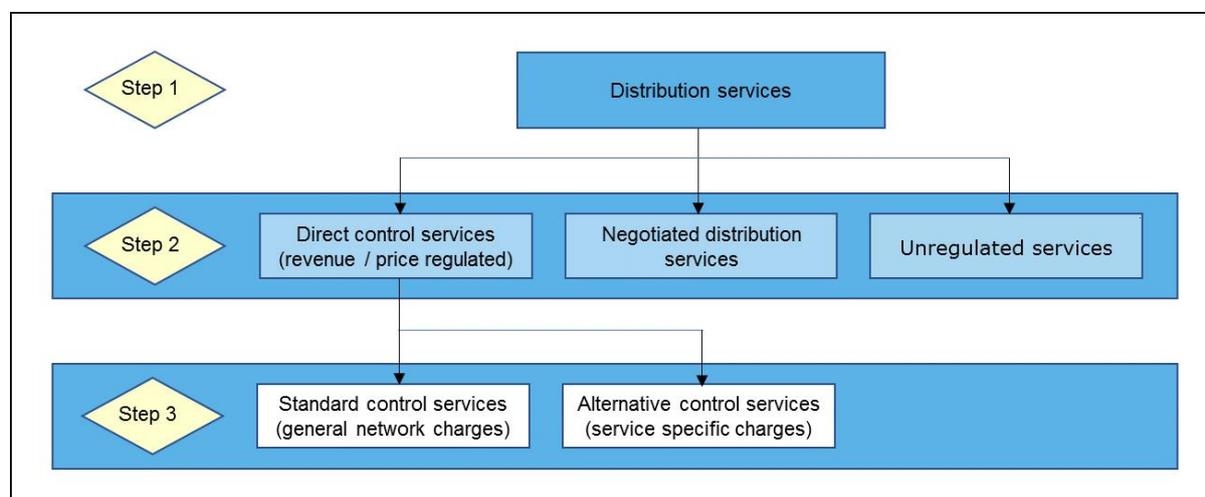
<sup>51</sup> NER, cl. 6.2.1(b).

service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for ring-fencing purposes. This provides distributors with flexibility to alter the exact specification (but not the nature) of a service during a regulatory control period. Where we make a single classification for a group of services, it applies to each service in the group.

- We are proposing that the pricing approach for any new services, introduced within the regulatory period – which clearly fall within one of the established service groupings – should be based on a similar service within that grouping. Rather than introducing new services at any time, distributors may notify us at the time of the annual price submission, regarding the new service and the price they plan to charge.
- In some circumstances, we may choose to classify a single service because of the particular nature of that service. In addition, a distribution service that does not belong to any existing service classification may be 'not classified', and therefore treated as an unregulated distribution service for that regulatory control period. New distribution services (that are created within a regulatory control period) are also to be treated as unregulated distribution services for the remainder of that regulatory control period.

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

**Figure 1.2 Distribution service classification process**



Source: NER, chapter 6, part B.

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system.<sup>52</sup> A distribution system is a 'distribution network, together with the

<sup>52</sup> NER, chapter 10, glossary.

connection assets associated with the distribution network, which is connected to another transmission or distribution system'.<sup>53</sup>

- 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.<sup>54</sup> 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.<sup>55</sup> We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The NER also requires us to consider the desirability of consistency in the form of regulation for similar services both within and beyond the jurisdiction.<sup>56</sup>

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.<sup>57</sup> These include the potential to develop competition in the provision of a service and how our classification may influence that potential, whether the costs of providing the service are directly attributable to the person to whom the service is provided, and the possible effect of the classification on administrative costs.

Our classification decisions determine how distributors will recover the cost of providing services.<sup>58</sup> 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 the use of a particular service directly (alternative control service). Alternative control classification is akin to a 'user-pays' system. We set service specific prices to enable the distributor to recover the full efficient cost of each service from the customers using that service. At a high level, we will classify a service as an alternative control service if it is either:

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

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<sup>53</sup> NER, chapter 10, glossary.

<sup>54</sup> NER, cl 6.2.1(a) note.

<sup>55</sup> NER, cl. 6.2.1(c)(1); NEL, s. 2F.

<sup>56</sup> NER, cl. 6.2.1(c).

<sup>57</sup> NER, cl. 6.2.2(c).

<sup>58</sup> 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).

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

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

No services have been classified as negotiated services for the next regulatory period.

In the case of some distribution services, we may determine there is sufficient competition that there is no need for us to classify the service as either a direct control or negotiated distribution service. That is, the market is sufficiently competitive, allowing customers to shop around for the best price. We refer to these distribution services as 'unregulated distribution services'. Broadly, pursuant to our Ring-Fencing Guideline, this means that while the distributor will continue to provide existing regulated distribution services, all unregulated distribution services or new services that come into existence within a regulatory control period must be separated from direct control services unless the distributor applies for, and receives, a waiver under the Guideline.<sup>59</sup>

## 1.3 Reasons for AER's position

This section sets out our service classification and reasons for the Victorian distributors' 2021–25 regulatory control period for each service group.

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

In submissions to our preliminary F&A, all five of the Victorian distributors supported our proposed approach to classification. Origin Energy and EnergyAustralia also noted that they are supportive of the approach to increase consistency across jurisdictions in the typology and classification of services.<sup>60</sup>

### 1.3.1 Common distribution service

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

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<sup>59</sup> AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

<sup>60</sup> For further detail see related submissions to the preliminary F&A, for example: <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/united-energy-determination-2021-25/aer-position>

The common distribution service grouping is a suite of activities concerned with providing a safe and reliable electricity supply to customers.<sup>61</sup> Activities within the common distribution service group are intrinsically tied to the network infrastructure and the systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution service activities on a regular basis. Providing a common distribution service involves a variety of different activities, such as the construction and maintenance of poles and wires used to transport energy across the shared network. The precise nature of activities provided to plan, design, construct and maintain the shared network may change over time. Regardless of what activities make up the common distribution service, this service group reflects the provision of access to the shared electricity network to customers.

Our position is to classify the common distribution service group as a direct control service. Each of the Victorian distributors holds the only electricity distribution licence for their respective distribution areas.<sup>62</sup> Under the *Electricity Industry Act 2000* (Vic), a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so or they are exempted from the requirement to obtain a licence.<sup>63</sup> These arrangements create a regulatory barrier preventing third parties from providing activities within the common distribution service group.<sup>64</sup> Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of activities classified as a common distribution service.

We must further classify direct control services as either standard or alternative control services.<sup>65</sup> Our position is to retain the current standard control classification for the common distribution service. There is no potential to develop competition in the market for common distribution service activities because of the barriers outlined above.<sup>66</sup> There is no material effect on administrative costs for Victorian distributors, the users, potential users or us by continuing this classification.<sup>67</sup> Further, distributors provide activities listed within the common distribution service through a shared network and therefore cannot directly attribute the costs of these services to individual customers.<sup>68</sup> We currently classify the common distribution service in Victoria and all other NEM jurisdictions as standard control services.<sup>69</sup>

Victorian distributors have requested a number of new activities to be included as part of the common distribution service. We discuss each of these in turn below.

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61 NER, Chapter 10 glossary.

62 Licences are issued by the Essential Services Commission of Victoria.

63 *Electricity Industry Act 2000* (Vic) s 16.

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

65 NER, cl. 6.2.2(a).

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

67 NER, cl. 6.2.2(c)(2), (3).

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

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

## Supply abolishment of basic connection

This activity includes the removal of a connection from the network, such as when a building is demolished and the connection is no longer required. The Victorian distributors stated that supply abolishment of basic connections has historically been classified as a standard control service.<sup>70</sup> They expressed concern that if provided on a cost recovery basis as an alternative control service, there may be an incentive for customers to abandon sites to avoid the charge. This could pose a safety risk if network connection infrastructure is not appropriately de-energised and removed.<sup>71</sup> We accept the distributor's assessment of the safety risks associated with customer abandonment of energised sites in order to avoid a fee. We therefore accept this justifies classifying supply abolishment as a standard control service under the common distribution service grouping.

## Bulk supply point metering

The Victorian distributors proposed that the common distribution service should include 'bulk supply point metering'.<sup>72</sup> 'Bulk supply point metering' refers to metering of connection points between the transmission system and the distribution system.<sup>73</sup> We agree that this a service that relates to measurement of Network Use of System (NUoS) charges levied on all distribution customers, rather than being a 'metering service' associated with a particular customer. In support, EnergyAustralia noted that the approach is *consistent with the global settlement rule change currently underway by the AEMC, which will remove the concept of a local retailer*.<sup>74</sup> We have included this service under the common distribution service in the service list at appendix B.

## Third party initiated network asset relocations/rearrangements

The Victorian distributors proposed that network ancillary services should include 'third party initiated network asset relocations/rearrangements' as a standard control service.<sup>75</sup> This

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<sup>70</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

<sup>71</sup> CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3.

<sup>72</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

<sup>73</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

<sup>74</sup> EnergyAustralia, *Submission on Victorian Preliminary Framework and Approach 2021-25*, p. 2.

<sup>75</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 13; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 5; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-4.

service is distinct from 'customer initiated network asset relocations/re-arrangements',<sup>76</sup> which is currently an alternative control service in Victoria and other jurisdictions.

The Victorian distributors stated that third party initiated network asset relocations/rearrangements are covered under the Essential Services Commission (ESCV) Guideline 14.<sup>77</sup> Under this Guideline and the *National Electricity (Victoria) Act 2015*, when a third party or customer requests for network assets to be moved or replaced, the third party pays a capital contribution to the cost of relocating or rearranging the assets. The capital contribution may not be equal to the cost of relocating or rearranging the assets: The distributor calculates the capital contribution by netting off any benefits that the distributor accrues because of the rearrangement or relocation of network infrastructure. For example, if the distributor replaces older poles with new poles on the part of its network that has been relocated, the benefits to the distributor in terms of incremental revenue because of deferred replacement expenditure will be factored into the capital contribution that the third party pays.<sup>78</sup>

While Victorian jurisdictional arrangements remain in place and Guideline 14 continues to apply to third party initiated asset relocations and rearrangements,<sup>79</sup> we propose classifying this as a standard control service, and listing it as an activity under the common distribution service grouping.

## Recoverable works

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

As a distributor provides recoverable works in connection with a distribution system, we consider this a distribution service. In the current regulatory control period, we did not classify this service in Victoria. Therefore, the service was unregulated.<sup>80</sup> This was because the cost of these works could be recovered through other avenues (e.g. under common law). However, following the introduction of our Ring-fencing Guideline, we have had cause to reconsider the classification of this service. As an unregulated distribution service, the service would have to be ring-fenced from the distribution business. We consider that this could increase the cost of these activities.

In response to the obligations outlined in our Ring-fencing Guideline, Victorian distributors applied for and obtained ring-fencing waivers for 'emergency recoverable works'. It is our view that the scope of this activity should include all types of recoverable works, including those of an emergency nature. Therefore, our proposed approach is to include an activity as

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<sup>76</sup> Customer initiated network asset relocations/rearrangements are those which are not subject to ESCV Guideline 14.

<sup>77</sup> Essential Services Commission Victoria, *Electricity Industry Guideline No. 14: Provision of services by electricity distributors*, April 2004

<sup>78</sup> Essential Services Commission Victoria, *Electricity Industry Guideline No. 14: Provision of services by electricity distributors*, April 2004, p.5.

<sup>79</sup> *National Electricity (Victoria) Further Amendment Act 2016*, cl.4.

<sup>80</sup> AER, Final framework and approach for Victorian electricity distributors - Regulatory control period commencing 1 January 2016, 24 October 2014, p.13.

part of the common distribution service called "Works to fix damage to the network (including recoverable works caused by a customer or third party)". We have updated appendix B accordingly.

We propose classifying this service as direct control. Furthermore, as an activity under the common distribution service group, we will treat recoverable works as a standard control service. Jemena supported this position in its request to us to replace the current F&A.<sup>81</sup> 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, we expect distributors to recover costs from responsible third parties. For the accounting treatment, in the forecast the expenditure on recoverable works and the amount recovered from third parties should always sum to zero. Classifying the service should have no net effect on distributor's costs. When the distributor recovers the cost of the repairs from a third party, the amount recovered is netted off the opex allowance, which means there is no overall cost to customers. Unrecovered costs of such repairs forms part of the normal allowance for repairs, consistent with the historic approach to the recovery of these costs.

The Department of Environment, Land, Water and Planning (DELWP) are not in favour of classifying recoverable works as standard control services. According to its submission, the use of a standard control classification may be a disincentive for distributors from using all reasonable efforts to recover costs from the responsible third parties.<sup>82</sup> We agree that this would be the case where distributors were able to obtain a revenue allowance for all potentially recoverable works and only net off from the opex allowance the amount actually recovered. Taking the assumption in the opex allowance – that the forecast of revenue from recoverable works and that recovered from third parties – always sums to zero, effectively eliminates the moral hazard cited by DELWP. We do not expect that distributors will require a step change to their opex allowance because of the classification of this service. Any unrecovered costs from potentially recoverable works are borne by the distributor, as is current practice. Our approach to this service is that the risk of recovery should sit with those who are in the best position to manage that risk – in this case, the distributors, not customers.

### **Support for another distributor during an emergency event**

We note that the Victorian distributors have listed a new activity under the common distribution service heading, labelled "support for another distributor during an emergency event".<sup>83</sup> The activity occurs if a distributor provides assistance to another distributor during an emergency event, for instance to help repair the network. This activity was first classified, in the final F&A, as part of the common distribution service for Queensland distributors and

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<sup>81</sup> Jemena Electricity Networks (Vic) Ltd, *Request for a replacement Framework and Approach*, 30 April 2018, p.5.

<sup>82</sup> DELWP, *Submission on Victorian Preliminary Framework and Approach 2021-25*, 29 October 2018, p. 2

<sup>83</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

we indicated at the time that we would roll out this approach across the NEM.<sup>84</sup> A distributor provides this service in connection with a distribution system, and we therefore consider it a distribution service. However, in the case of an emergency event, where the distributor is called upon to assist another distributor, the works performed are not on the distributor's shared network. Therefore, we consider that the distributor is entitled to recover the costs of the assistance it provides to its customer, which in this scenario is another distributor. While we propose to classify these activities as standard control services, we expect the distributor to seek recovery of the costs of the assistance provided.

A classification of standard control is appropriate because there is no potential for the development of competition.<sup>85</sup> While the costs for the service provided are directly attributable to the distributor who is requesting the service<sup>86</sup>, the cost for providing the emergency assistance are paid for by all customers of the distributor making the request in DUoS charges. Therefore, the assistance provided is similar in nature to the distributor responding to their own emergency works, which they provide as part of the common distribution service.<sup>87</sup>

There is no overall cost to distribution customers when their distributor assists another during an emergency event. Similar to the accounting treatment of emergency recoverable works (see above), the expenditure incurred when a distributor assists another during an emergency event and that recovered from that distributor should always sum to zero. The corollary of this is that distribution customers of the other distributor will pay, as part of their DUoS, if emergency assistance is provided to their distributor.

## Stand-alone power systems

AusNet Services proposed that stand-alone power systems or SAPS (also known as 'remote area power systems' or RAPS) should be treated as an input into a standard control service, so that AusNet Services is able to provide this service in the event of regulatory change mid-way through its next regulatory control period.<sup>88</sup>

The regulatory treatment of stand-alone power systems as an alternative to network replacement expenditure is currently under consideration by the Council of Australian Governments Energy Council (COAG EC) and the AEMC. In 2016, Western Power submitted a rule change request to the AEMC, proposing to extend the definition of the term 'distribution service' to allow network businesses the ability to island distribution customers from the network, and provide them with stand-alone power systems (such as integrated solar PV, battery, and diesel generator nanogrids or microgrids). This would be an alternative to replacement of network infrastructure.<sup>89</sup> The AEMC's Determination found that Western Power's proposed rule change require changes to laws, rules, and state and

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<sup>84</sup> AER, *Final Framework and Approach, Energex and Ergon Energy 2020-25*, July 2018, p. 21.

<sup>85</sup> NER, cl. 6.2.2(c)(1).

<sup>86</sup> NER, cl. 6.2.2(c)(5).

<sup>87</sup> NER, cl. 6.2.2(c)(4).

<sup>88</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 8.

<sup>89</sup> Western Power, *Rule change proposal - Removing barriers to efficiency network investment*, 8 September 2016.

territory instruments, including the National Electricity Law.<sup>90</sup> In 2018, the AEMC commenced its *Review of regulatory framework for stand-alone power systems* and published a terms of reference for the review.<sup>91</sup> The AEMC released a draft report on 20 December 2018 examining regulatory arrangements for customers who are currently connected to the grid and are transitioned to off-grid supply by their distributor (priority 1 of the review).<sup>92</sup> Under the terms of reference for the review, the AEMC is required to provide the COAG Energy Council with a final report for priority 1 by 31 May 2019.

Stand-alone power systems do not satisfy the current definition of a distribution service under the NEL. We are therefore unable to classify this service. Further, there is currently uncertainty about what the eventual regulatory framework for SAPS will look like.

Like the AEMC, we are supportive of enabling off-grid power supply.<sup>93</sup> We anticipate that in the event of changes to the legal and regulatory framework to enable SAPS under the NEL, we would consider any necessary changes to distributor service classifications as part of transitional arrangements.<sup>94</sup>

### 1.3.2 Network ancillary services

Network 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). Network ancillary services involve work on, or in relation to, parts of the Victorian distributors' respective distribution networks. Therefore, similar to the common distribution service, only the relevant distributor may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than the Victorian distributors providing network ancillary services in their respective distribution area.<sup>95</sup> Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that the Victorian distributors possess significant market power in providing network ancillary services.<sup>96</sup>

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

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<sup>90</sup> AEMC, *Final rule determination: National electricity amendment (alternatives to grid-supplied network services) rule 2017*, 19 December 2017.

<sup>91</sup> See <https://www.aemc.gov.au/market-reviews-advice/review-regulatory-frameworks-stand-alone-power-systems>.

<sup>92</sup> AEMC, *Draft Report; Review of the Regulatory Frameworks for Stand Alone Power Systems; Priority 1 - 18 December 2018*.

<sup>93</sup> AEMC *Final rule determination: National electricity amendment (alternatives to grid-supplied network services) rule 2017*, 19 December 2017, p. i.

<sup>94</sup> See <https://www.aemc.gov.au/market-reviews-advice/review-regulatory-frameworks-stand-alone-power-systems>.

<sup>95</sup> NEL, s. 2F(a).

<sup>96</sup> NEL, s. 2F.

Further, we intend to classify network ancillary services as alternative control services because the Victorian distributors provide these services to specific customers.<sup>97</sup> As such, the cost of each network ancillary service is directly attributable to an individual customer.<sup>98</sup> This results in costs that are more transparent for customers.

We adopt this view even though network 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 the distributors, users or potential users of the network and us.<sup>99</sup> This is because classifying network ancillary services as alternative control services is consistent with the current approach.

To the extent that the provision of network ancillary services becomes 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 network ancillary service.

### Network safety services

In their letters requesting that we amend or replace the current F&A, the Victorian distributors proposed that 'site visits related to location of underground cables' should be included as a new service under the description of the network safety services group.<sup>100</sup>

Jemena submitted that the existing dial before you dig service is desktop based and does not involve site visits.<sup>101</sup> However, contractors undertaking excavation work regularly request that Jemena accurately locate cables on the site and agree to fund the cost of a site visit. Jemena proposed to create a new chargeable service for this activity.<sup>102</sup> We have included this service as part of the network safety services service group, which is an alternative control service, in the services list at appendix B.

In response to our preliminary F&A, AusNet Services identified a number of services listed in the Service Classification guideline, but not included in the F&A at appendix B, which they would now like to include in the classified services list for Victorian distributors.<sup>103</sup> These services are:

- Third Party request for de-energising wires for safe approach;
- Supply enhancement of basic connection services (e.g. upgrade from single phase to three phase);

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<sup>97</sup> NER, cl. 6.2.2(c)(5).

<sup>98</sup> NER, cl. 6.2.2(c)(5) – this includes a small number of identifiable customers.  
NER, cl. 6.2.2(c)(2).

<sup>100</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 12; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.6; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 6, p. A-5.

<sup>101</sup> Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 6.

<sup>102</sup> Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 6.

<sup>103</sup> AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 7.

- Calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER; and
- Power factor correction.

All of the services listed are provided by means of, or in connection with, a distribution system.<sup>104</sup> As a result, they are distribution services which can be classified as either direct control or negotiated services. We consider a classification of direct control is justified, primarily because of the barriers to entry to potential competitors. In most cases, only a distributor can perform the services on its network.<sup>105</sup> We further classify these services as alternative control services, primarily because the services are provided to a sub-set of customers who are identifiable.<sup>106</sup>

We have added "Third party request for de-energising wires for safe approach" under the network safety service group. The other services listed above are related to connections and are included within the connection application and management services grouping.

### Customer requested supply outage

In its submission, Origin Energy requested confirmation whether the classification of this service, which was previously unregulated, to alternative control, applies to individual site outages, multiple site outages or both. Further, Origin sought confirmation about whether, if work performed under such a planned interruption causes an unintended interruption to another customer's site, without consent, the distributor is liable for compensation as a result.<sup>107</sup>

The services we classify in the F&A provide distributors with guidance as to the range of services or activities they can provide under given classification(s). Subject to their obligations, such as under licences or other instruments, distributors can choose whether to provide a specific service, in which case they must submit pricing proposals within the reset process.. We do not direct distributors or provide guidance about the potential liabilities that might arise because of providing a service.

It is within the discretion of the distributor whether it submits prices for customer requested supply outages— for our approval— that include individual customers, commercial and industrial and multi-site customers. Arrangements for large customers can be quite different to small customers, and can vary between distributors and jurisdictions. We will consider the proposals put forward by the distributors within the reset process. Any specific services the distributors propose under this grouping will be subject to price caps, unless the NER requires otherwise.

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<sup>104</sup> See definition of a distribution service in NER, chapter.10.

<sup>105</sup> NER, cl. 6.2.1(c)(1)(a), NEL section 2F,

<sup>106</sup> NER, cl. 6.2.2 (c)(5).

<sup>107</sup> Origin Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 1

## Service visits

In their letters requesting us to replace or amend the current F&A, the Victorian distributors included 'service visit' in their proposed list of alternative control services. The distributors requested this service in order to recover the costs incurred when the distributor sends out a service truck to investigate an issue at a customer's request, only to find that the issue does not relate to the mis-operation of the distributor's equipment or infrastructure.<sup>108</sup> The result is a 'wasted truck visit'.

A wasted truck visit is not a service in itself, but is rather an activity that may take place in the course of delivering a distribution service. We therefore propose not to classify this as a service, but consider that it a distributor could list it as a chargeable item in its proposed price list for alternative control services. For example, a distributor might send a truck to a customer's premises to perform a customer requested alternative control metering service and find that no one is at home and the service cannot be performed. In this case, the distributor can charge the customer for that truck visit because it occurred in the course of performing an alternative control service.

Conversely, the distributor might send a truck to a customer's premises after receiving a complaint about a power outage or power quality issue. The distributor may do this based on a legitimate concern that the distributor's network may be the source of the problem, only to find on arrival that the issue is on the customer side of the connection point. In this case, we consider that the distributor should recover the cost of this truck visit through DUoS. This is because the wasted truck visit occurred as part of the distributor performing the common distribution service (i.e. maintaining the safety and reliability of the shared networks).

In our Determinations for the 2016-20 regulatory control periods for Victorian distributors, we classified "fault response - not distributor's fault" and "wasted attendance - not distributor's fault" as alternative control services.<sup>109</sup> We recognise that our proposed approach to service truck visits represents a change in our approach to the previously approved regulatory treatment of wasted truck visits.

We recognise that this may cause issues for distributors, as they will be unable to deter customers from making spurious complaints by charging the customer for a wasted truck visit. However, we think that removing a wasted truck visit charge will also remove potential disincentives for customers to report legitimate network issues, which would otherwise be disadvantageous to network reliability and safety.

In its submission, EnergyAustralia expressed support for our approach not to treat truck service visits as a distribution service but rather an input into a broader service. It agrees that in some cases, it may be difficult for a customer to establish the cause of supply

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<sup>108</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 11; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.6.

<sup>109</sup> AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 23; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-21; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-21; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-21; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-21.

outages, which might lead to a safety issue where outages go unreported or where the customer attempts to reconnect supply.<sup>110</sup>

To provide further clarity, distributors may charge a wasted truck visit fee, as a line item within the pricing list, for the applicable alternative control distribution service. Distributors will not be able to charge a wasted truck visit fee in relation to the provision of standard control services.

### **Watchman lights or security lights**

Watchman lights or security lights are used to improve security, such as to illuminate a customer's premises. Security lights that are mounted on distribution assets are a distribution service. The service involves construction, relocation of distribution assets (where necessary), operation and maintenance, and billing to customers, such as local councils. In many cases, security lights are inherently tied to the network.

We intend to classify watchman or security lighting as a direct control service and further, as an alternative control service.

Distributors are in a unique position to be able to affix security lighting to a distribution network asset.<sup>111</sup> Other parties would need access to poles and easements to hang security lighting assets. Similar to network services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the Victorian distributors.<sup>112</sup> Based on this consideration, we propose to classify watchman or security lights as a direct control service.

As direct control services, we must further classify watchman or security lighting as either standard control or alternative control services.<sup>113</sup> Our position is to classify security or watchman lighting as an alternative control service, primarily for the reason that, even though the potential for competition is currently limited, the Victorian distributors can directly attribute the costs of providing watchman or security lighting services to a specific set of customers. This includes local councils, large customers, and other government agencies.<sup>114</sup>

We therefore propose to classify installation, repair and maintenance of security or watchman lighting as an alternative control service. It was previously unregulated.

### **Customer requested provision of electricity network data**

In its submission to our preliminary F&A, Jemena proposed that we modify the provision of network data service to distinguish between two types of data; network data and consumption data, and their different uses.<sup>115</sup> In its submission, Jemena identified how applicants use different types of data. We acknowledge that network data and consumption

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<sup>110</sup> Energy Australia, *Submission on Victorian Preliminary Framework and Approach* - 9 November 2018, p. 2.

<sup>111</sup> NEL, s. 2F(d).

<sup>112</sup> NEL, s. 2F(a)(d).

<sup>113</sup> NER, cl. 6.2.2(c).

<sup>114</sup> NER, cl. 6.2.2(c)(5).

<sup>115</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3

data is different and is requested by different parties at different times. However, for the purposes of classification, the differences as described are not significant enough to warrant separating the services. Even if separated, both services would still arise as a result of customer requests for data and be classified as alternative control services. We consider that the distinction between the services can be adequately identified in the pricing schedule, which will describe the service and the charges applied in a range of scenarios. The current name and description of the service is consistent with that outlined in our Service Classification Guideline,<sup>116</sup> as well as with distributors in other jurisdictions.

Origin Energy also sought clarification on the nature of the charges that distributors would levy when providing data request services.<sup>117</sup> As noted above, details related to the pricing structure for services provided by each distributor form part of the pricing proposal submitted as part of the regulatory proposal, which we will consider in making our decision. It is beyond the scope of the F&A to decide what specific charges might apply.

### 1.3.3 Connection services

A connection service refers to the services a distributor performs to:

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

In 2016, the Victorian Government required distributors to implement chapter 5A of the NER.<sup>118</sup> To align service classifications with the new arrangements and connection charge policies, Victorian distributors requested that we redefine and reclassify connection services in the F&A.<sup>119</sup>

In past regulatory determinations, our classification of connection services has largely followed the jurisdictional approaches and we have not sought to align connection services across the jurisdictions.

In its request to replace the current F&A, Jemena proposed that the services and service descriptions of connection services be aligned to those categories outlined in chapter 5A of the NER.<sup>120</sup> Service classification for Victorian distributors in the 2016-20 determinations defined three types of connections: two routine types of connections for customers up to 100 amps, customers above 100 amps and connections requiring augmentation.<sup>121</sup> With the

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<sup>116</sup> AER, *Electricity Distribution Service Classification Guideline*, pgs.10 & Appendix A; Baseline services list, p. 5.

<sup>117</sup> Origin Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 1

<sup>118</sup> National Electricity (Victoria) Further Amendment Bill 2015.

<sup>119</sup> CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.1; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.1.

<sup>120</sup> Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 3.

<sup>121</sup> AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 20; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-17; AER, *United Energy Distribution Determination Final Decision - 2016-2020*,

adoption of Chapter 5A of the NER, we have defined connections as 'basic', 'standard', or 'negotiated'. In addition, we use 'non-standard connections' and 'enhanced connection services' to describe other less frequently requested types of connections. This approach allows better alignment between the classification of connection services, Chapter 5A of the NER, our Connection Charge Guideline under Chapter 5A, and the distributors' connection policies.

As part of our Service Classification Guideline,<sup>122</sup> we published a list of baseline services that outlined our approach to the classification of connection services. In submissions in response to our preliminary F&A, AusNet Services expressed concerns that we would impose the classification of connection services listed in the Guideline, without further consultation.<sup>123</sup> Likewise, CitiPower, Powercor and United Energy supported the classification of services we outlined in the preliminary F&A, but not the Guideline. The distributors were concerned that we had not sufficiently allowed for jurisdictional and operational requirements when classifying services within jurisdictions, and were instead taking a blanket approach.<sup>124</sup>

The intent of the Guideline is not to impose or enforce consistency of classification. We adopt much of the typology of the Service Classification Guideline, in relation to connection services, but not the classification of those services from the Guideline. The connections typology used in the Guideline is also consistent with the NER. Where appropriate, we have departed from the Guideline and classified connection services for Victorian distributors to meet operational and jurisdictional requirements.

## Basic connections

Our proposed approach is to classify basic connections as direct control and further, as an alternative control service for the 2021-25 regulatory period. This is consistent with the classification in the 2016-20 determinations for Victorian distributors, where routine connections were alternative control (both for customers with connections up to and above 100 amps).<sup>125</sup>

Basic connection services are connection services for retail customers under the following circumstances where:

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May 2016, p. 13-18; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-18; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-18.

<sup>122</sup> The guideline took effect on 1 October 2018.

<sup>123</sup> AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 1 & 4.

<sup>124</sup> CitiPower, Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 2.

<sup>125</sup> AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 20; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-17; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-18; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-18; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-18.

- either: (1) the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, a basic connection service, or; (2) a retail customer that is, or proposes to become, a micro-embedded generator.<sup>126</sup>
- the provision of the service requires minimal or no augmentation of the distribution network.
- a model standing offer has been approved by the AER for providing that service as a basic connection service.

A new residential property owner having their house connected to the network with minimal or no augmentation is a typical example of a basic connection service. This type of connection request is common to anyone wanting to connect to the network to use electricity and therefore we consider that we should directly regulate the price of these services.

We consider that the current alternative control classification for basic connection services is appropriate for the following reasons:

- There are barriers to market entry. Distributors approve access and materials connected to their network infrastructure.
- The cost of providing the service is directly attributable to a specific customer. As there is no need for augmentation or extension of the shared network in performing a basic connection service, the cost revenue test does not apply.

## Standard connections

Our proposed approach is to classify standard connections as direct control and further, as a standard control service. This is consistent with the classification in our 2016-20 determinations for Victorian distributors, where new connections requiring augmentation were a standard control service.<sup>127</sup>

A standard connection service is a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant, and for which a model standing offer has been approved by the AER.<sup>128</sup> What differentiates this service from a basic connection is that standard connections typically require a network extension or network augmentation. This means that it is subject to a cost revenue test under the AER's Connection Charge Guideline.

We consider that the current standard classification for standard connection services is appropriate. There is no potential for competition to develop in providing this service. Where a new connection requires an extension or augmentation of the shared network, there is potential benefit for other customers on the shared network. To ensure that the distributor

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<sup>126</sup> NER cl. 5A.A1 defines a 'micro-embedded generator' as a retail customer who owns or operators an embedded generator that is connected to the network Australian Standard AS 4777 (Grid connection of energy systems by inverters).

<sup>127</sup> AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 20; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-17; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-18; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-18; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-18.

<sup>128</sup> NER, cl. 5A.A1.

only recovers efficient costs, standard connections are subject to a cost revenue test. This test determines the customer connection charge by subtracting the net present value of the new customer's future DUoS payments over a 30-year period (or 15 years for businesses) from the upfront cost of the connection.<sup>129</sup>

## Negotiated connections

Our approach is to classify negotiated connections as a direct control service, and further, as a standard control service. We did not classify negotiated connection services in our 2016-20 determinations for Victorian distributors.

Negotiated connections are connection services that are delivered under the negotiating provisions in Chapter 5A of the NER<sup>130</sup>. These types of connection services are not part of the negotiated service framework under Chapter 6 of the NER. Connection services for larger customers, who require special connection requirements, are typically delivered on a negotiated basis. These services often require some form of augmentation to the network in order to provide the connection service requested by the customer.

We propose to include connections under Chapter 5 of the NER in the negotiated connections grouping, which is subject to the negotiation framework set out in Chapter 5A of the Rules, discussed above.<sup>131</sup> Chapter 5 of the NER generally regulates connection of generators to the transmission network. However, at times, connection of other large loads to the distribution network can take place under Chapter 5.<sup>132</sup> While the distributors already provide connection services under Chapter 5, the regulatory treatment of these connection services was not explicit in the 2016 Determination for Victorian distributors.

We consider that a standard control service classification is appropriate for the following reasons:

- Distributors retain some market power as they have control over whether or not a particular connection is contestable.
- In Victoria, a standard control classification for this service is not a constraint on competition. Jurisdictional requirements under the Essential Services Commission's Guideline 14 enable the distributors to apply a rebate scheme and a real estate developer equalisation scheme that ensures competitive neutrality. The rebates provided are equal to the present value of the incremental DUoS revenue that the distributor will earn from the new connection. These rebates are available to customers that choose to source connection works from contestable service providers.<sup>133</sup>
- A classification of standard control is also appropriate because connection costs are based on the full cost of providing the service, subject to a cost revenue test that takes

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<sup>129</sup> AER, Connection Charge Guideline.

<sup>130</sup> See NER, cl. 5A, Part C.

<sup>131</sup> See NER, cl. 5A.C.1 Important to note that negotiated connections are not part of the negotiated services framework under Chapter 6 of the NER.

<sup>132</sup> NER, cl. 5.1.2(a)(1).

<sup>133</sup> CitiPower/Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3.

into account future revenue earned from tariffs paid by a connecting customer. Application of the cost revenue test means a connecting customer will eventually pay the full cost of their connection and contribute to shared network costs. This payment, however, will occur through both ongoing payment of distribution tariffs and, if required, a capital contribution. All existing customers will benefit from the connection of new customers even though, at first, those costs will not have been fully recovered from the connecting customers.

Jemena, CitiPower/Powercor and United Energy suggested that negotiated connection charges should remain a standard control service.<sup>134</sup> In its submission to our preliminary F&A, EnergyAustralia also supported a standard control classification for negotiated connections. In its view, the regulatory oversight of the negotiation process, provided through the standard control classification, is appropriate – given the high value and complexity of negotiated connection contracts.<sup>135</sup> At present, negotiated connections are a standard control service in Victoria, and capital contributions are calculated according to our Connection Charge Guideline<sup>136</sup> and outlined in the Victorian distributors' respective Connection Policies.<sup>137</sup>

## Connection application and management services

Our proposed approach is to classify connection application and management services as direct control, and further, as alternative control services.

Connection management services are activities associated with connections, like:

- requests for premises de-energisation or re-energisation
- temporary connections (such as a builders connection)
- customer overhead line replacements or re-location
- customer requested upgrades to their connection (such as undergrounding)
- calculation of site specific loss factors when required under the NER
- assessing applications to undertake network asset relocations
- undertaking design work to assess connection costs and technical studies to assess network impacts of new connections
- supply enhancement (e.g. upgrade from single phase to three phase)
- Calculation of a site-specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity.<sup>138</sup>

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<sup>134</sup> CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 8; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. A-8.

<sup>135</sup> EnergyAustralia, *Submission on Victorian Preliminary Framework and Approach 2021-25 - 9 November 2018*, p. 2.

<sup>136</sup> AER, *Connection Charge Guideline 2012*, p.39.

<sup>137</sup> CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 8; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. A-8.

<sup>138</sup> As per NER, cl. 3.6.3(b1).

- Power factor correction
- site inspections associated with new connections, and
- registered participant support services associated with connections under Chapter 5 of the NER.

The Victorian distributors have included 'embedded networks' in their letters requesting we amend or replace the current F&A.<sup>139</sup> In this F&A, we include embedded network management as an activity in the connection application and management services group. For embedded networks, the Victorian distributors are mostly required to correctly abolish National Metering Identifiers (NMIs) (when customers become part of an embedded network), coordinate bulk abolishment of requested sites and remove meters, and check the designs of the embedded network operator to ensure that customers who want to maintain a stand-alone NMI are not mistakenly incorporated into the embedded network or disconnected from supply.

We have grouped these activities under connection management and application services in our service classification list at appendix B. The Consumer Challenge Panel 17 (CCP 17) supported our approach to embedded network management and temporary connections in its submission to the preliminary F&A.<sup>140</sup>

We consider that an alternative control service classification is appropriate for the following reasons:

- There are barriers to market entry. Distributors approve access and materials connected to their network infrastructure.
- The service is provided to an identifiable customer or subset of customers.

In its letter to us to replace or amend the F&A for Victorian distributors, Jemena proposed that temporary connections, which are connections provided for a short period after which the connection is removed, should be distinguished as a stand-alone service.<sup>141</sup> Further, in its submission to our preliminary F&A, Jemena proposed that we modify the description of temporary connection service to include the various types of temporary connections as some are charged under a set fee, while a quote is provided for others.<sup>142</sup>

In the Explanatory Statement to our Service Classification Guideline, we detailed our preferred approach to service descriptions. We stated that, "*service descriptions should clearly relate to the nature of the activities being performed by the distributor. They should not reflect the purpose of the activity or the mechanism by which costs are recovered.*"<sup>143</sup> As a result, we consider that the delineation between fee-based and quoted services best sits within the distributor's proposed pricing for relevant services.

<sup>139</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 15; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 7. Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.8.

<sup>140</sup> CCP 17, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, pp. 9-10.

<sup>141</sup> Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 4.

<sup>142</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 5.

<sup>143</sup> AER, *Explanatory Statement, Electricity distribution Service Classification Guideline*, September 2018, p. 11.

Similarly, Jemena also requested that we include temporary disconnection and subsequent reconnection services as part of the connection application and management services grouping.<sup>144</sup> We agree that customers may request a range of disconnection or de-energisation services, for a range of reasons and that the service provided to each customer may vary according to the circumstances of the request. However, we also consider that the description of the connection application and management services is sufficiently broad, to be able to include the variations of connection applications that customers might request. The description of connection application and management services explicitly states that the grouping includes, *but is not limited to* the services listed. The purpose of the description is not to describe all the individual activities that a distributor might provide under a single heading, but to encompass a broad range of examples. The alternative control service pricing schedule allows the distributor to list the individual services/activities it provides along with the proposed prices.

### Enhanced connection services

Our proposed approach is to classify enhanced connection services as direct control, and further, as an alternative control service.

Enhanced connection services cover activities to provide customers with a higher standard of electricity supply that exceeds the minimum technically feasible standard. These include services where customers request higher levels of reliability or three phase electricity, where customers request the construction of a second connection from the distribution network to the customer (a reserve feeder), or where a customer requests a supply enhancement.

We consider that an alternative control service classification is appropriate for the following reasons:

- There are barriers to market entry. Distributors approve access and materials connected to their network infrastructure.
- The service is provided to an identifiable customer or subset of customers.

We classified enhanced connection services and reserve feeder construction as negotiated services in our 2016-21 determination. While customer-requested supply enhancements were not previously classified. This approach, if continued would bring the distributors into conflict with their ring-fencing obligations, which does not permit the provision of services which are not classified or other services, without a waiver.<sup>145</sup> We have granted the Victorian distributors waivers from their ring-fencing obligations in relation to the provision of these services, in anticipation that the services would be classified as alternative control in the next regulatory period.<sup>146</sup>

A classification of alternative control also provides a clear indication of the efficient price of service provision to customers and potential competitors.

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<sup>144</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p.5.

<sup>145</sup> AER, *Ring-Fencing Guideline*, S. 3.1(b), October 2017, p.11, other services are defined within the Guideline to include negotiated services, p. 8.

<sup>146</sup> See AER, *Ring-fencing waiver applications final decision* - December 2017, p. 26.

For the reasons above, we consider that an alternative control service classification is more appropriate.

## Community network upgrades

In AusNet Services' letter to us to amend or replace the current F&A, it proposed a new service to allow community groups to negotiate collectively for exportable PV connection to the network, which AusNet Services calls 'community network upgrades'. In the preliminary F&A, we treated this as a connection related service.

Our initial concerns surrounding AusNet Services' proposal was in its treatment of community-based applications for exportable PV connections as a single connection rather than multiple connections.<sup>147</sup> We considered this treatment was not consistent with the NER. Specifically, Chapter 5A of the NER prevents a distributor from charging a capital contribution to a retail customer where the application is for a basic connection, or the customer's request does not exceed the relevant threshold set by the distributor's connection policy.<sup>148</sup>

In our preliminary F&A, we did not classify the proposed service. In doing so we recognised that the capability of the regulatory framework to address the issue of the increasing penetration of distributed energy resources (DER) is actively being considered outside of the Victorian F&A process. One example is the AEMC's forward work program, which is looking at increasing penetration of DER from the perspective of whether the existing rules require amendment. As a result, we considered that the F&A is not the appropriate avenue to explore the implications of increasing penetration of PV in the community.

In its submission, CCP 17 recognised the pressures that increased penetration of behind-the-meter distributed energy resources is placing on networks. However, it supported our approach in the preliminary F&A in not classifying the proposed service for now, submitting that AusNet Services' proposed solution is not appropriate at this time. CCP17 suggested instead that we conduct further stakeholder consultation prior to releasing the F&A.<sup>149</sup>

However, since publishing the preliminary F&A, further analysis of the proposed service indicates that this service is better described as customer requested (in this case a collective) network augmentation. Customer connections are not a part of this service. The network augmentation would be provided in response to a community request to augment the network to enable higher PV exports. This type of upgrade cannot be imposed on customers and can only be provided on the basis of a customer request.

Having regard to the matters set out or referenced in rule 6.2.1(c), including the form of regulation factors set out in section 2F of the NEL, we consider that this service should be classified as a direct control service. Of particular importance is the fact that only the distributor can augment the upstream network to increase the capacity for PV exports. This

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<sup>147</sup> AER, *Preliminary F&A Victorian 2021-25 Determinations*, pp. 35-37.

<sup>148</sup> NER, cl. 5A.E.1.

<sup>149</sup> CCP 17, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, pp. 9-10.

means that there are significant barriers to entry in the market for this service.<sup>150</sup> There are no close substitutes for the service,<sup>151</sup> and the distributor's market power is unlikely to be mitigated by any countervailing power.<sup>152</sup>

The AER further considers that, having regard to the matters set out in rule 6.2.2(c), this service should be classified as an alternative control service. Of particular importance is that:

- the fact that only the distributor can augment the upstream network to increase the capacity for PV exports means that the potential for the development of competition in the market for this service is very limited.<sup>153</sup>
- other than being provided in response to a collective request, the service has close similarities with 'customer initiated network asset relocations/rearrangements', which is currently classified as an alternative control service.<sup>154</sup>
- the service will be offered to an identifiable subset of customers, whom the costs of - augmentation are directly attributable.<sup>155</sup>

It is important to note that those customers funding the upstream augmentation will not have sole entitlement to the additional capacity and will not be able to prevent subsequent PV installations from accessing the additional capacity that may be available. We consider that this should be made clear as part of the contract for provision of the collective upgrade service.

The new service: "Community Network Upgrades" will include activities that relate to collective customer upstream augmentations. We have defined the service broadly and we expect distributors to flesh out details of the service activities in their regulatory proposals. We are unaware of any unintended consequences of classifying such a service, but are open to submissions on the proposal during the determination process.

The Department of Environment, Land Water and Planning (DELWP) are opposed to the classification of a service, which could see community energy projects paying for the costs of network augmentation. The Department argued that the Victorian Government is working to recognise and reduce barriers faced by community energy groups, planning for and implementing renewable energy projects. As a result, expecting community energy projects to pay for the costs of network augmentation, with no guarantee that they will not be constrained from exporting energy to the network in the future, will not be in the interests of those who could benefit from such projects.<sup>156</sup>

We understand the Department's concerns, having taken this position in the preliminary F&A,<sup>157</sup> particularly in relation to connection related services. However, in considering the

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<sup>150</sup> NEL, s. 2F(a).

<sup>151</sup> NEL, section 2F(e).

<sup>152</sup> NEL, section 2F(d).

<sup>153</sup> NER, cl. 6.2.2(c)(1).

<sup>154</sup> NER, cl. 6.2.2(c)(4).

<sup>155</sup> NER, cl. 6.2.2(c)(5).

<sup>156</sup> DELWP, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, p. 3.

<sup>157</sup> AER, *Preliminary F&A Victorian 2021-25 Determinations*, pp. 35-37.

nature of the service and the similarities with existing services, we consider that a classification of alternative control is consistent with past decisions on network enhancement services and increases the clarity and predictability of the way services are regulated.

Further, we recognise that a service classification which allows distributors to negotiate with a collective on augmentation but which does not lead to guaranteed access to the export capacity they have contributed may not seem fair. However, the issue of firm access is outside of the scope of this F&A and other changes to the regime would need to be considered. On the other hand, not providing the opportunity for customers to seek these upgrades may also not serve the interests of customers who require augmentation to support rapidly increasing penetration of distributed energy resources. We consider that the approach we have taken is reasonable in the circumstances. It enables customers as a collective to seek timely augmentation of the shared network to allow greater use of distributed energy. Separately, further consideration may need to be given on access rights that customers should have more broadly.

### 1.3.4 Metering services

All electricity customers have a meter that measures the amount of electricity they use.<sup>158</sup>

On 26 November 2015, the AEMC made a final rule to open up competition in metering services and give consumers more opportunities to access a wider range of metering services.<sup>159</sup> The new arrangements commenced on 1 December 2017 and required changes to the NER and the National Electricity Retail Rules (NERR).<sup>160</sup> Following the AEMC rule change to introduce competition in metering and related services, the Victorian Government deferred metering competition in Victoria through an Order-In-Council.<sup>161</sup> Consequently, Victorian distributors are exclusive providers of metering services to residential and small business customers consuming up to 160 MWh of electricity per annum. Our proposed classification of metering services in Victoria is consistent with our classification approach in the 2016-20 Determination.

#### Type 1 to 4 metering services

Type 1 to 4 meters provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. Type 1 to 4 meters are competitively available<sup>162</sup> and we do not currently regulate them in Victoria or in most other jurisdictions—they are not classified and therefore are unregulated distribution services and our position is for them to remain so. Under the Victorian Government Order-In-Council, new or replacement meters for small customers do not have to be type 4 meters.<sup>163</sup> In other

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<sup>158</sup> All connections to the network must have a metering installation (NER, cl. 7.3.1A(a)).

<sup>159</sup> AEMC, *Competition in metering services information sheet*, 26 November 2015.

<sup>160</sup> AEMC, *Competition in metering services information sheet*, 26 November 2015.

<sup>161</sup> Victorian Government Order-In-Council, No. S 346, Thursday 12 October 2017.

<sup>162</sup> NER, cl. 7.2.3(a)(2) and 7.3.1.A(a).

<sup>163</sup> Victorian Government Order-In-Council, No. S 346, Thursday 12 October 2017, cl. 5.

jurisdictions, a metering coordinator must ensure that all new or replacement meters for small customers are type 4 meters, unless a customer refuses a type 4 meter.<sup>164</sup>

## Type 5 and 6 metering services

Victorian distributors are monopoly providers of type 5 (interval) and type 6 (accumulation) meters and have the role of metering coordinator, metering provider, and metering data provider for AMI meters.<sup>165</sup> In 2006, the Victorian Government initiated a roll-out of smart meters to all households and small businesses with electricity use of up to 160 MWh per annum under the Advanced Metering Infrastructure (AMI) program. AMI meters can be remotely read and can be remotely turned on and off. Under a Victorian government derogation, AMI meters are classified as type 5-6 meters.<sup>166</sup>

Type 5-6 metering services, including services for AMI meters as specified under the Victorian Government Order-In-Council, as alternative control services. Prices for Victorian distributors (or local network service providers, LNSPs) are provided under Chapter 6 and Chapter 11 of the NER.<sup>167</sup> Prices are also set with reference to the Advanced Metering Infrastructure (AMI Tariffs) Order-In-Council of 2013.<sup>168</sup>

## 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. The Victorian distributors are the monopoly providers of type 7 metering services in Victoria.

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.<sup>169</sup> We intend to classify type 7 metering services as direct control services and further, as alternative control. This is a continuation of the current classification of type 7 metering services.<sup>170</sup> AusNet Services agreed that the appropriate classification is alternative control, making the point that this service uses the same IT systems as other alternative control services, including type 5 metering, and that the service is provided to an

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<sup>164</sup> NER cl. 7.8.3 and 7.8.4.

<sup>165</sup> Victorian Government Order-In-Council, No. S 346, Thursday 12 October 2017, cl. 3 and 4 and 9.

<sup>166</sup> Victorian Government Order-In-Council, No. S 346, Thursday 12 October 2017, cl. 2(b).

<sup>167</sup> Victorian Government Order-In-Council, No. S 346, Thursday 12 October 2017, cl. 9.

<sup>168</sup> Victorian Government Order-In-Council, No. S 216, 18 June 2013.

<sup>169</sup> NER, cl. 6.2.2(c)(1).

<sup>170</sup> AER, *Final decision AusNet Services distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-16; AER, *Final decision CitiPower distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision Powercor distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision United Energy distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p.13-15; AER, *Final decision Jemena distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15.

identifiable subset of customers.<sup>171</sup> CitiPower/Powercor/United Energy similarly supported an alternative control classification, but proposed it be included in the 'Type 5 and 6 (inc. smart metering) services where the distributor remains responsible' service group.<sup>172</sup> While we agree that Type 7 metering should remain alternative control, we see no benefit in including type 7 metering under the 'Type 5 and 6 (inc. smart metering) services where the distributor remains responsible' service group.

### **Auxiliary metering services (type 5 and 6 including smart meters) where the distributor remains responsible**

The Victorian distributors also provide a range of metering related services to specific customers on request. Examples include requested meter tests and additional meter reads or equipment alterations. As AMI smart meters are included in type 5 meters in Victoria, this service also includes remote de-energisation and re-energisation of metering.

We consider that there is no potential to develop competition for type 5-6 auxiliary metering services, and that the services provided are delivered to an identifiable customer.<sup>173</sup> We intend to classify type 5-6 auxiliary metering services where the distributor remains responsible as direct control services, and further, as alternative control. This is a continuation of the current classification of type 5-6 auxiliary metering services.<sup>174</sup>

### **Metering exit services**

In letters to replace the current F&A, as well as submissions to the preliminary F&A, Victorian distributors requested inclusion of metering exit services.<sup>175</sup> Metering exit services allow the distributor to recover the written down value, as well as the efficient costs of removing and disposing of AMI meters. This currently occurs when brownfield sites become embedded networks, resulting in the removal of the existing meters. We classified meter exit services for the current regulatory period as alternative control.<sup>176</sup>

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<sup>171</sup> AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 7,

<sup>172</sup> CitiPower/Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 4,

<sup>173</sup> NER, cl. 6.2.2(c)(1) and 6.2.2(c)(5).

<sup>174</sup> AER, *Final decision AusNet Services distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-17; AER, *Final decision CitiPower distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision Powercor distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision United Energy distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p.13-15; AER, *Final decision Jemena distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15.

<sup>175</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 15; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 7. Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. A-6. CitiPower/Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3, AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 6., Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 4.

<sup>176</sup> AER, *Final Framework and Approach for Victorian Electricity Distributors* - October 2014, p. 101.

We consider that an alternative control service classification continues to be appropriate for the following reasons:

- there is no potential for competition to develop as the distributors own the meters being removed; and
- the service is provided to an identifiable customer or subset of customers.<sup>177</sup>

We consider that metering exit services should be included as an activity under the auxiliary metering services grouping.

### Contestable type 5-6 metering services

In its submission to our preliminary F&A, Jemena requested that we classify a number of services in the event that the Victorian Government moves to develop a competitive market for type 5-6 metering services. Services include: planned supply interruption - retailer requested, and; emergency maintenance of failed metering equipment not owned by the distributor.<sup>178</sup> Similarly, the distributors submitted that metering exit services would also be required if metering was opened to full contestability in Victoria.<sup>179</sup>

We understand that the Victorian Government is considering introducing competition in the metering services. However, at the time of publishing, there has been no announcement that they plan to introduce a contestable market in the near future. Thus, at this stage, it is currently not clear that contestability will be introduced. Therefore, we do not propose to classify these services. Should the Victorian Government indicate before our determination that it intends to establish contestability in metering services before or during the next regulatory period, and then we will reconsider our classification approach. This is consistent with our approach to the proposed introduction of contestability in other jurisdictions such as Queensland, where we have maintained the status quo until further clarification regarding the jurisdiction's intentions become clear.<sup>180</sup>

## 1.3.5 Public lighting

The Victorian distributors operate and maintain the majority of public lighting systems throughout Victoria. The distributors provide these services on behalf of local councils and government departments responsible for public lighting in Victoria, as required under clause 10 of their respective electricity distribution licences.<sup>181</sup>

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<sup>177</sup> NER, cl. 6.2.2(c)(1&5).

<sup>178</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25*, p. 4.

<sup>179</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25*, p. 4., AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25*, p. 6., CitiPower, Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25*, pp. 3-4.

<sup>180</sup> AER - *Final framework and approach for Energex and Ergon Energy* - April 2014, p. 31.

<sup>181</sup> See: <https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-licences-and-exemptions/electricity-and-gas-licences#tabs-container2>.

The NER does not define public lighting services, however they are defined in the Victorian Public Lighting Code, which we administer.<sup>182</sup> Further, we have consistently defined public lighting services in other distribution determinations as:

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.<sup>183</sup>

We also propose to include emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that the Victorian distributors do not provide at the time of our distribution determination. LED public lighting is an example of emerging public lighting technologies. However, emerging public lighting technology may become available during the 2021–25 regulatory control period. We must also make a distinction for Greenfield sites, such as new housing estate developments. Greenfield sites are contestable under the Victorian Public Lighting Code.<sup>184</sup> That is, estate developers can procure and construct any public lighting asset from any source. Distributors need not be involved in this procurement process other than to ensure the assets can be technically integrated into the electricity network.

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

While the Victorian distributors do not have a legislative monopoly over these services, a monopoly position exists to some extent.<sup>185</sup> This is because the Victorian distributors own the majority of public lighting assets.<sup>186</sup> That is, other parties would need access to poles and easements to hang their own public lighting assets. Similar to the common distribution service, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the Victorian distributors.<sup>187</sup>

Based on the above analysis, our position is to classify public lighting services, including emerging technology, as direct control services.<sup>188</sup> This is consistent with public lighting's current classification.

As direct control services, we must further classify public lighting services as either standard control or alternative control services.<sup>189</sup> Our position is to classify public lighting as an alternative control service for the following reasons:

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<sup>182</sup> See: [http://www.esc.vic.gov.au/Energy/Distribution/RI\\_FinalPublicLightCodeFollow04ReviewNCM\\_Apr05](http://www.esc.vic.gov.au/Energy/Distribution/RI_FinalPublicLightCodeFollow04ReviewNCM_Apr05).

<sup>183</sup> *Final framework and approach for Victoria*, October 2014, p. 42; AER, *Final framework and approach for TasNetworks*, July 2017, p. 28.

<sup>184</sup> Essential Services Commission Victoria, *Public lighting code, version 2*, December 2015.

<sup>185</sup> NEL, s. 2F(d).

<sup>186</sup> NEL, s. 2F(a).

<sup>187</sup> NEL, s. 2F(a)(d).

<sup>188</sup> NER, cl. 6.2.1.

<sup>189</sup> 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 for new public lighting assets.<sup>190</sup>
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future— if the Victorian Government implements a contestability regime. 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.<sup>191</sup>
- there would be no material effect on administrative costs to the Victorian distributors, users or potential users or us. This is because we are retaining the current classification.<sup>192</sup>
- the Victorian distributors can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.<sup>193</sup>

In the 2016-20 regulatory control period, we classified alteration and relocation of distributor public lighting assets, and new public lights as negotiated distribution services. New lighting types not subject to a regulated charge and new public lighting at Greenfield sites are not classified. For the reasons listed above, we consider that there is sufficient basis to move away from the previous classifications, so that public lighting services in Victoria are classified as alternative control services for the 2021-25 regulatory control period.<sup>194</sup>

### 1.3.6 Unregulated distribution services

Unregulated distribution services is the term we use to describe distribution services which we have not classified as either direct control or negotiated distribution services.<sup>195</sup> These services are provided on an unregulated basis and are potentially provided by other service providers in a competitive market. This group of services is particularly important as the number and types of services offered by distributors is growing and changing.

In October 2017, we published the amended Electricity Distribution Ring-fencing Guideline.<sup>196</sup> Our Ring-fencing Guideline interacts with a number of regulatory instruments, including our service classification decisions. Specifically, our service classification decisions have an impact on how the ring-fencing obligations apply to each distributor for its next regulatory control period.<sup>197</sup> Under our Ring-fencing Guideline, unregulated distribution services are subject to functional and accounting separation from direct control services.

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<sup>190</sup> NER, cl. 6.2.2(c)(1).

<sup>191</sup> NER, cl. 6.2.2(c)(1).

<sup>192</sup> NER, cl. 6.2.2(c)(2).

<sup>193</sup> NER, cl. 6.2.2(c)(5).

<sup>194</sup> NER, cl. 6.2.2(c)(3).

<sup>195</sup> AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

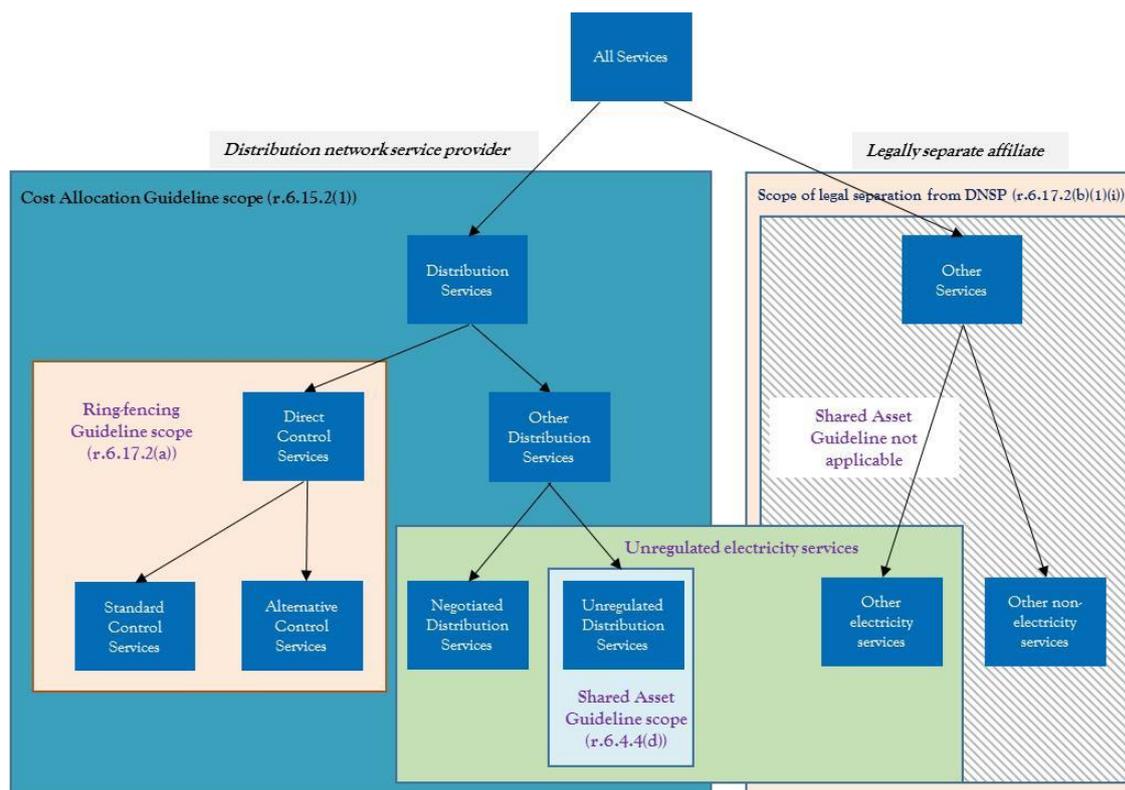
<sup>196</sup> AER, *Ring-fencing guideline electricity distribution*, October 2017.

<sup>197</sup> AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

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 and affiliated entities may provide other electricity services. For the purposes of this 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.<sup>198</sup>

**Figure 1.3 Distribution services linkage to ring-fencing**



Source: AER

Compliance with our Ring-fencing Guideline became mandatory on 1 January 2018. Distributors, when considering what unregulated distribution services they offer, should refer to the examples contained in the explanatory statement to the Ring-fencing Guideline<sup>199</sup> and their unregulated revenue streams. For example, a distributor may earn additional revenue from (for example) NBN Co., by permitting NBN Co. to hang its wires from distribution network 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. We describe these as "activities related to 'shared asset facilitation' of distributor assets" under the common distribution service grouping and the revenue derived is treated in accordance with the shared asset guideline.

<sup>198</sup> AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

<sup>199</sup> AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, Appendices A and B, pp. 77–86.

## Transmission network support

In AusNet Services' letter requesting that we amend or replace F&A, it proposed a new unregulated service, 'Transmission Network Support'. Transmission network support services are provided by distributors to support a transmission network when AEMO detects the risk of high voltage, exceeding defined operating limits, during periods of light load on the transmission network. During such periods, AEMO may direct a distributor to switch off zone station capacitors in order to reduce voltage on the transmission network.

This is because low power flow on the transmission network can lead to high voltage that may exceed defined operating limits. Switching off capacitors at zone substations within the distribution network can help reduce voltages on the transmission network by increasing the level of reactive power that is drawn from the transmission network. In the 2018 Victorian Annual Planning Report for transmission, AEMO stated that it has managed high transmission system voltages following the closure of the Hazelwood Power Station through a temporary arrangement with distributors to switch off a total of 350 MVar reactive power of distribution substation capacitors.<sup>200</sup> While distributors may have provided this service on an ad hoc basis historically, AEMO appears to be requiring this service largely than it has in the past because of the closure of the Hazelwood Power Station.

At present, AusNet Services does not receive revenue in respect to this service. However, it intends to formalise and charge AEMO for this service as an unregulated service. AusNet Services considered that revenue earned in this manner should be treated in accordance with the Shared Asset Guideline (SAG).<sup>201</sup> We do not agree with this approach. We see no reason to depart from the current practice, which is consistent with the provision of the service as part of the common distribution service. The common distribution service is classified as a standard control service.

In our preliminary F&A, we sought submissions on alternative options for classification of transmission network support. We offered three options on how to treat the service:

1. a standard control service – to be provided as a regulatory obligation and recovered through DUoS charges – as reflected by current practice;
2. an unregulated contestable service - subject to ring-fencing obligations or a waiver; or
3. as an alternative control service - with prices subject to regulation by the AER.

We received four submissions in response to this issue, with a range of positions:

- AusNet Services maintained its view that we should not regulate the service.<sup>202</sup>
- CCP 17 supported AusNet Services being able to earn revenue from providing the service. It further submitted that the beneficiaries of the service extend beyond AusNet Services' customers and hence recovering the cost from its customers exclusively is inequitable. CCP 17 also suggested that we review the SAG to more fairly share the

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<sup>200</sup> AEMO, *Victorian annual planning report - Electricity transmission network planning for Victoria*, July 2018, p. 28.

<sup>201</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 8.

<sup>202</sup> AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 4.

benefits of shared asset usage and thereby make it more generally applicable to frequency control services, and other services requested by AEMO. Until a review of the SAG is completed, CCP 17 recommended that an alternative control classification is the most appropriate option.

- The Victorian Department of Environment, Land, Water and Planning (DEWLP) submitted that we should classify the service in such a way that allows the service costs to be shared among all Victorian customers. The rationale for which is that all customers benefit from the reliability and safety benefits of the service, so all should contribute, rather than the costs being borne by the customers of a particular distributor.<sup>203</sup> Accordingly, the Department submitted that the most appropriate classification is alternative control.<sup>204</sup>
- AEMO's submission provided further detail on transmission support services. Its submission supported classifying the service as part of the common distribution service - a continuance of the current arrangements. AEMO submitted that under the Rules,<sup>205</sup> Network Service Providers (NSPs) have "*an obligation to 'arrange for operation of that part of the national grid over which it has control in accordance with instructions given by AEMO'*". AEMO makes it clear in its submission that the instructions to switch off capacitors is done to maintain system security. AusNet Services is required to comply with these instructions as part of its core obligations. A failure to comply with AEMO's instructions could attract a civil penalty. AEMO further submitted that the impact on NSPs of this activity is quite low. Switching off capacitor banks is not labour intensive and can be performed within the control room via "computer system keyboard entries". The material life of a capacitor is not adversely affected by switching and AEMO does not expect that AusNet Services, or other NSPs, "will incur material additional expenditure or wear and tear on the assets as a result of the switching".<sup>206</sup>

Our position on classifying Transmission Network Support Services is driven by the service classification framework set out in the NEL and the NER. In our view, this kind of transmission network support service is a distribution service because it is provided by means of, or in connection with, a distribution system.<sup>207</sup> As a result, it is a service that may be classified as either a direct control or negotiated distribution service.<sup>208</sup>

Having regard to the matters set out or referenced in rule 6.2.1(c), including the form of regulation factors set out in section 2F of the NEL, we consider that this service should be classified as a direct control service. Of particular importance is the fact that there are significant barriers to entry. There are no close substitutes for the service.<sup>209</sup> AEMO has identified that significant investment, in the order of between \$32.6 and \$44.5 million would be required by an alternative provider to meet the identified need. As a result, the service, if

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<sup>203</sup> DEWLP, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, p. 3

<sup>204</sup> AusNet Services would charge AEMO for the service, AEMO is funded by all customers.

<sup>205</sup> NER, cl. 5.2.3(e).

<sup>206</sup> AEMO, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 21 November 2018, pp. 3-4

<sup>207</sup> See definition of a distribution service in NER, chapter.10.

<sup>208</sup> NER, cl. 6.2.1(a).

<sup>209</sup> NEL, section 2F(e).

supplied as a stand-alone service by an alternate provider, may not be economic. AEMO is currently unaware of any practical non-network options to meet the identified need, but is seeking further information.<sup>210</sup>

The AER further considers that, having regard to the matters set out in rule 6.2.2(c), this service should be classified as a standard control service. Of particular importance is that:

- the potential for the development of competition in the market for this service is currently very limited.<sup>211</sup> As a stand-alone service the high set-up costs, relative to the potential revenue available, mean that the service may not be economic. If we do not regulate the service, as proposed by AusNet Services, prices would not be constrained by substitutes in the market.<sup>212</sup>
- the marginal cost of providing the service incurred by a distributor in providing these services to AEMO is very low.<sup>213</sup> Most of the costs relating to the service have or are being recovered from all customers already. At a high level, the pricing principles outlined in the NER are that prices should reflect the efficient cost of providing those services.<sup>214</sup> This suggests that if an alternative control service price were to be set by us, it would be close to if not actually nil. The low cost of provision means that the fact that costs are directly attributable to the transmission network operator (clause 6.2.2(5)) carries less weight than it otherwise would.
- The current practice, whereby AusNet Services does not charge a third party for provision of the service, is consistent with a standard control classification.<sup>215</sup> The costs for standard control services are recovered from all customers of a distributor through DUoS charges. As a result, a classification of standard control would represent a continuation of the current arrangements. Further, AEMO noted the importance of the service to system stability and security. Under the NER and NEL, network service providers have obligations to assist AEMO in the proper discharge of its power system security responsibilities.<sup>216</sup> Clarifying that this service forms part of the common distribution service would formalise the current approach. It would continue to allow AEMO to direct distributors to provide the service when and as required. The efficient costs of providing the service would be reflected in DUoS charges, paid by all customers of the distributors.

The submission by DEWLP noted that the ongoing transition to a new energy system would include changes to the way the power system is operated. Which in turn may require distributors to take actions to maintain voltage and frequency within acceptable limits.<sup>217</sup> In addition to that, in the future, non-network options may assist to open a viable market for

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<sup>210</sup> AEMO, *Victorian Reactive Power Support: Regulatory Investment Test for Transmission Project Specification Consultation Report*, May 2018, pp, 10-11.

<sup>211</sup> NER, cl. 6.2.2(c)(1).

<sup>212</sup> NER, cl. 6.2.2(c)(2).

<sup>213</sup> AEMO, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 21 November 2018, p. 4

<sup>214</sup> NER, cl. 6.18.5(a).

<sup>215</sup> NER, cl. 6.2.2(c)(3).

<sup>216</sup> NEL, cl. 2D(1) and NER cl. 4.3.4(a) and 5.2.3(e).

<sup>217</sup> DEWLP, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, p. 3

these types of services.<sup>218</sup> As a result, while we consider that a classification of standard control is appropriate for this service for the forthcoming regulatory period, we may need to review the decision at the next determination, taking into account any market development during that time.

Taking into account all the factors above, we propose to classify transmission support services as standard control services, as part of the common distribution service, to be provided as directed by AEMO in accordance with the obligations of network service providers under the NER.<sup>219</sup>

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<sup>218</sup> AEMO, *Victorian Reactive Power Support: Regulatory Investment Test For Transmission Project Specification Consultation Report*, May 2018, pp, 10-11.

<sup>219</sup> NER, cl. 5.2.3(e).

## 2 Forms of control

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.<sup>220</sup> This section sets out our positions, together with our reasons, on the forms of control to apply to the Victorian distributors' direct control services for the 2021–25 regulatory control period. This section also sets out our positions on the formulae to give effect to these control mechanisms.

As discussed in section 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 classification of the Victorian network business' distribution services.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A.<sup>221</sup> 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. The formulae cannot be altered between the F&A and the making of the determination unless we consider that there has been a material change in circumstances that justifies departing from the formulae set out in that F&A.<sup>222</sup> However, without affecting the content of a Determination that has already been made, an F&A paper may be amended or replaced in accordance with the rules and with consultation.<sup>223</sup>

### 2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2021–25 regulatory control period:

- Revenue cap — for services we classify as standard control services.
- Revenue cap — for types 5 and 6 (including smart meters) metering services we classify as alternative control services
- Caps on the prices of individual services — for services we classify as alternative control services.

### 2.2 AER's assessment approach

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

- the form of the control mechanisms<sup>224</sup>
- the formulae to give effect to the control mechanisms

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<sup>220</sup> NER, cl. 6.2.5(a).

<sup>221</sup> NER, cl. 6.12.3(c).

<sup>222</sup> NER, cl. 6.12.3(c1).

<sup>223</sup> NER, cl. 6.8.1(a)(2), 6.8.1(c)(3).

<sup>224</sup> NER, cl. 6.2.5(b).

- the basis of the control mechanism.<sup>225</sup>

The NER sets out the form of control mechanisms that may apply to both standard and alternative control services.<sup>226</sup>

- 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)<sup>227</sup>

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

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

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

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

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

- revenue yield control (average revenue cap)

An average revenue cap is a cap on the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the TAR by a particular unit (or

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<sup>225</sup> NER, cl. 6.2.6(a).

<sup>226</sup> NER, cl. 6.2.5(b).

<sup>227</sup> 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.

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 positions on the control mechanisms for the Victorian distributors' standard control services, we have only considered the continuation of the revenue cap, or the adoption of price caps or an average revenue cap. We have not considered the other forms of control mechanisms for standard control services. We remain of the view we have expressed previously - namely, that the other alternative control mechanisms 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.<sup>228</sup>

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.<sup>229</sup> We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.<sup>230</sup>

We have also not considered a hybrid approach as our previous deliberations considered the higher administrative costs outweigh the potential benefits of this form of control.<sup>231</sup>

In considering our positions on the control mechanisms for the Victorian distributors' 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. We have concluded that no such reason exists.

## 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

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<sup>228</sup> AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 52

<sup>229</sup> 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.

<sup>230</sup> NEL, s. 7.

<sup>231</sup> For example, see: AER, *Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

- 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 that 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.<sup>232</sup>

We note that the Powercor/CitiPower/United Energy submission sought us to make provisions in the price control formula for contingent projects.<sup>233</sup> Our approach to this in the 2016-20 regulatory control period was to address contingent projects through recalculation of x-factors. An example of this was with respect to the Rapid Earth Fault Current Limiters (REFCLs) – tranche two where we recalculated the x-factors after allocating the incremental opex to opex and the incremental capex amount to distribution services in the Post-tax Revenue Model.<sup>234</sup>

Our approach to x-factors for standard control services includes incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. This means there is an established process in place for x-factor updates during the regulatory control period. We therefore consider that the continuation of the current approach with respect to contingent projects during the 2021-25 regulatory control period provides administrative simplicity.

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

## 2.2.2 Alternative control services

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

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential

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<sup>232</sup> NER, cl. 6.2.6(a).

<sup>233</sup> CitiPower/Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3.

<sup>234</sup> AER, *Final Decision Powercor Australia Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche two*, 31 August 2018, p. 46.

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

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

We must state what the basis of the control mechanism is in our distribution determination.<sup>235</sup> This may utilise elements of Part C of chapter 6 of the NER with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass through mechanism.<sup>236</sup>

We note that we have received a separate application from AusNet Services and Powercor/CitiPower/United Energy for the inclusion of a cost-pass through in the revenue cap for metering.

Our position is to include a factor in the revenue cap formula for metering to address cost-pass throughs in line with the approach taken in the revenue cap for standard control services. The NER is not prescriptive on the form of the control mechanism for alternative control services. However, the NER states that the control mechanism may utilise elements of the building block for standard control services. For example, the distribution determination might provide for the application of clause 6.6.1 to pass through events with necessary adaptations and specified modifications.<sup>237</sup>

We therefore consider it consistent with the principles of the NER to include a cost-pass through in the metering control mechanism. Inclusion of a cost-pass through mechanism best reflects the ability to deliver the efficient cost of providing these services should a pass-through event occur. While a 1 per cent materiality threshold applies to pass throughs for standard control services, if applied to alternative control services revenue this threshold would be inappropriately low. This is because alternative control services revenue, in total, is a small fraction of standard control services revenue. Typically in the order of 10 per cent or less. Using 1 per cent of such small revenues as a pass through threshold would transfer operational risk to customers rather than have it managed by the DNSP – the party best able to manage that risk. Our decision is to establish a pass through mechanism for alternative control services but to retain the existing pass through materiality threshold, being 1 per cent of standard control service revenue. This means that an event, which increases the cost of

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<sup>235</sup> NER, cl. 6.2.6(b).

<sup>236</sup> NER, cl. 6.2.6(c).

<sup>237</sup> NER, cl. 6.2.6(c).

providing metering services, would only qualify for a potential pass through if the event's costs were at least 1 per cent of standard control service revenue, as provided for in the NER.

For consistency of approach, we have included a C factor in the formula that gives effect to the revenue cap for metering, in line with the equivalent factor in the revenue cap formula for standard control services.

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

## 2.3 Reasons for AER's approach — control mechanism and formulae for standard control services

Our decision is to maintain a revenue cap for the Victorian distributors' standard control services for the 2021–25 regulatory control period. We consider the application of a revenue cap control mechanism best meets the factors set out under clause 6.2.5(c) of the NER.

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

A revenue cap will also result in benefits to consumers through a higher likelihood of revenue recovery at efficient costs and will provide better incentives for demand side management. Furthermore, our recent approach to the operation of the revenue cap has reduced the magnitude of overall price variability during a regulatory control period, which has been a concern in the past. We provide our consideration of these issues below.

### 2.3.1 Efficient tariff structures

In deciding on a control mechanism, the NER requires us to have regard to the need for efficient tariff structures.<sup>238</sup> We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

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

Our previous considerations on the interaction between a control mechanism and its ability to deliver efficient tariff structures during a regulatory control period relied solely on the incentive properties of the different types of control mechanisms.<sup>239</sup> However, recent changes to the NER now require us to undertake a supplementary assessment of the efficiency of a distributor's tariff structures, which are set out in a tariff structure statement.

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<sup>238</sup> NER, cl. 6.2.5(c)(1).

<sup>239</sup> 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.

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 consider explicitly 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.

A distributor's tariff structure statement sets out the tariff structures it can apply over a regulatory control period.<sup>240</sup> The tariff structure statement should show how a distributor applied the distribution pricing principles<sup>241</sup> to develop its tariff structures and the indicative price levels of tariffs for the coming five-year regulatory control period. The network pricing objective of the distribution pricing principles is the focus for a distributor when developing its network tariffs. The objective is that:<sup>242</sup>

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

We must approve a tariff structure statement unless we are reasonably satisfied it will not comply with the distribution pricing principles or other relevant requirements of the NER.<sup>243</sup>

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

Through the initial tariff structure statements, many distributors will be introducing more cost reflective tariff structures, such as demand-based tariffs. In our assessment, we found no evidence to suggest that Evoenergy's average revenue cap or other distributors' revenue caps inhibited the ability to develop or implement efficient tariff structures. Therefore, we consider that efficient tariff structures can occur under both average revenue cap and

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<sup>240</sup> NER, cl. 6.18.1A(a)(3).

<sup>241</sup> 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).

<sup>242</sup> NER, cl. 6.18.5(a).

<sup>243</sup> NER, cl. 6.12.3(k).

revenue cap control mechanisms. On this basis, we also consider efficient tariff structures are likely to occur under all forms of control mechanisms, including price caps.

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

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

### **2.3.2 Administrative costs**

In deciding on a control mechanism, the NER requires us to have regard to the possible effects of the control mechanism on administrative costs.<sup>244</sup> We consider, where possible, a control mechanism should minimise the complexity and administrative burden for the distributor, users, or potential users or us.

Generally, we consider there is little difference in administrative costs between control mechanisms under the building block framework in the long run. However, we consider the continuation of a revenue cap control mechanism to the Victorian distributors' standard control services would have the least complexity and administrative burden. The continuation of a revenue cap would impose no additional administrative costs for us, the Victorian distributors, users, or potential users.

In contrast, at least, the Victorian distributors and we will incur additional administrative costs 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 the requirements in 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.<sup>245</sup> We note maintaining a revenue cap control mechanism for the Victorian distributors' standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior 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**

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<sup>244</sup> NER, cl. 6.2.5(c)(2).

<sup>245</sup> NER, cl. 6.2.5(c)(3).

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.<sup>246</sup> We consider the continuation of a revenue cap control mechanism for the Victorian distributors' standard control services delivers consistent regulatory arrangements for these services across jurisdictions.

Apart from Evoenergy, all other electricity distributors' who are currently subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. We have decided to apply a revenue cap to Evoenergy's standard control services for the 2019–24 regulatory control period.<sup>247</sup> This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore maintaining the Victorian distributors' revenue cap control mechanism will ensure consistent regulatory arrangements for these services across jurisdictions. For these reasons, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(4) of the NER than an alternative mechanism.

### 2.3.5 Revenue recovery

We consider that a control mechanism should give a distributor an opportunity to recover efficient costs. In addition, 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.<sup>248</sup>

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

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

In contrast, control mechanisms where revenue depends on energy sales (such as average revenue caps or price caps) provides distributors with incentives to understate sales forecasts and adjust tariffs to gain revenues above efficient cost levels.<sup>249</sup> A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.<sup>250</sup> We

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<sup>246</sup> NER, cl. 6.2.5(c)(4).

<sup>247</sup> ActewAGL Distribution, *Response to AER preliminary framework and approach*, April 2017, p. 11.

<sup>248</sup> 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.

<sup>249</sup> For example, see: AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67; AER,

<sup>250</sup> For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.<sup>251</sup>

In terms of efficient revenue recovery, we consider a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.<sup>252</sup>

### 2.3.6 Pricing flexibility and stability

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

We consider that price flexibility is primarily influenced by the distribution pricing principles and the side constraint.<sup>253</sup> 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 are. However, price instability can occur under all control mechanisms because the NER require various annual price adjustments regardless of the control mechanism.<sup>254</sup>

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

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

We have somewhat addressed this issue in our recent determinations by applying a rolling unders and overs account which includes an additional true up for the estimated under and over recovery of revenues for the year in between (year  $t-1$ ).<sup>255</sup> The inclusion of this estimated year helps smooth year-on-year revenue and tariff adjustments because the

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<sup>251</sup> NEL, s. 7.

<sup>252</sup> NEL, s. 7.

<sup>253</sup> The side constraint is a mechanism imposed on a distributor which limits the change in the expected average revenue for a tariff class, weighted by tariff component, from one regulatory year to the next.

<sup>254</sup> These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from transmission network service providers.

<sup>255</sup> 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 stability across regulatory control periods, we consider an average revenue cap can result in greater price volatility compared to a revenue cap.<sup>256</sup> 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 position is to maintain the Victorian distributors' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling unders and overs account reduces the magnitude of this effect.

### **2.3.7 Deliberately under recovered revenue in the unders and overs account**

We accept that there are times when distributors may make a business decision to recover below their allowed level of revenue such as by choosing to price services at lower levels than would be allowable under the revenue cap.<sup>257</sup> In these cases, the distributor decides to accept the under-recovery for reasons of its own commercial interest.

In particular, while it is possible that the under recovery may result in a financial loss, it is also possible for an under recovery to involve a strategic financial choice that reduces costs to a degree that exceeds the reduced revenue.<sup>258</sup>

This is in contrast to under recovery that arises due to a natural variation between forecast quantities of a services offered and actual quantities achieved. This type of under-recovery is disadvantageous to the distributor.

If a distributor chooses, in its own interests, to under-recover revenue, it is no worse off than had it not made that under recovery. In these circumstances, therefore, we do not consider that it is in the interest of consumers that the revenue that is not recovered be able to be recovered later, as this would be inefficient and would give the distributor an unintended additional benefit.

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<sup>256</sup> AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 67–69.

<sup>257</sup> See for example TasNetworks' demand based time of use tariff incentive as discussed in TasNetworks' response to AER Information Request 009, 29 March 2018, p. 5.

<sup>258</sup> For example, by accepting lower rates for tariffs that peak at critical times, more customers choose those tariffs. These tariffs discourage demand at peak times and reduce strain on the network lowering costs.

Accordingly, as part of our proposed revenue cap, we will not count this revenue as an under recovery for the purpose of the under and overs account and, by extension, will therefore not subsequently increase the total allowable revenue in future years.

Instead, we will require that any deliberately under recovered revenue in a year t will be added to the annual revenue in year t prior to calculating any under or over recovery in year t.

The below example does not constitute the entirety of an unders and overs account which will need to be maintained. It merely demonstrates the principle of how the deliberately under-recovered revenue should be captured.

**Table 2.4 Example calculation of DUoS unders and overs recovery including deliberately under recovered revenue**

	Year t
Revenue from DUoS charges	\$1,000,000
Revenue deliberately under-recovered in year	\$100,000
(A) Revenue from DUoS charges including deliberately under-recovered revenue	\$1,100,000
(B) Total allowable revenue	\$1,200,000
(A) - (B) Under/over recovery	(\$100,000)

### 2.3.8 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.<sup>259</sup> Where prices are cost reflective, consumers and providers of demand side management face efficient incentives because they can take into account the cost of providing the service in decision making.

Under a revenue cap, a distributor's revenue is fixed over the regulatory control period. A distributor can therefore improve its financial position by reducing costs. This creates an incentive for a distributor to undertake demand side management projects that reduce total costs, even if that means the distributor does not build new assets or replace existing

<sup>259</sup> Generally, peak demand is referred to as the maximum load on a section of the network over a very short time period.

ones.<sup>260</sup> We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales, such as in a price cap.

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

### 2.3.9 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.<sup>261</sup> 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.<sup>262</sup> Below is the proposed formula to apply to the Victorian distributors' standard control services revenues. We consider that the formula gives effect to the revenue cap.

**Figure 2.1 Final positions revenue cap to be applied to the Victorian distributors' standard control services**

1.  $TAR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij}$   $i = 1, \dots, n$  and  $j = 1, \dots, m$  and  $t = 1, 2, \dots, 5$
2.  $TAR_t = AAR_t + I_t + B_t + C_t$   $t = 1, 2, \dots, 5$
3.  $AAR_t = AR_t \times (1 + S_t)$   $t = 1$
4.  $AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$   $t = 2, \dots, 5$

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.

<sup>260</sup> 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.

<sup>261</sup> NER, cl. 6.8.1(b)(2)(ii).

<sup>262</sup> NER, cl. 6.12.3(c1).

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

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

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

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

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

$S_t$  is the s-factor for regulatory year t.<sup>263</sup> As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.<sup>264</sup>

However, we are currently undertaking a review of the STPIS. How the s-factor will apply within the revenue cap formula may depart from the current arrangements. Depending on the outcome of our review, provision to adjust revenues for performance against the STPIS may be made through either the  $S$  or  $I$  factors as set out in this F&A paper. If the review is completed in time, the distributors may need to apply the revised STPIS for the 2021–25 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities<sup>265</sup> from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

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<sup>263</sup> 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.

<sup>264</sup> AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

<sup>265</sup> 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.

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

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

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

Our position is to apply caps on the prices of individual services (price caps) in the 2021–25 regulatory control period to all of the Victorian distributors' alternative control services with the exception of metering services. We propose classifying the following services as alternative control services:

- public lighting services
- network ancillary services
- basic connection services
- metering services.

In the current regulatory period, we have applied a revenue cap to the type 5 and 6 and smart metering service, which is currently classified as an alternative control service, as this service is not subject to competition. We propose to continue this approach. Victorian distributors' remaining alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2021–25 regulatory control period best meets the factors set out under clause 6.2.5(d) of the NER.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.<sup>266</sup> For example, the price caps could be based on a building block approach, or a modified building block cost build up. We have set out our proposed formulae that will give effect to the price cap control mechanisms in figure 2.2 and figure 2.3 below. However, it is at the distributor's discretion as to the approach it undertakes to develop its initial prices.

Prices for certain ancillary services will be determined on a quoted basis. Prices for quoted services are based on quantities of labour and materials with the quantities dependent on a particular task. For example, where a customer seeks a non-standard connection, which may involve an extension to the network, the distributor may only be able to quote on the service once it knows the scope of the work. Because of this uncertainty, our 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.

A further consideration relates to the treatment of new services that might be offered by the Victorian distributors within the regulatory control period. Where such services were not

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<sup>266</sup> NER, cl. 6.2.6(c).

identified at the time of the AER Determination but for which the service clearly falls within one of the established service groupings, we propose that a quoted price approach be adopted based on a similar service within that same service grouping. For example, the price for a new type of security lighting would be set based on the same approach as a similar security lighting service. This approach would give the distributors additional flexibility to introduce new services while offering consumers the protections associated with price regulation. If there was no other similar service, the new service would be unregulated and may therefore be subject to ring-fencing restrictions that affect use of the Victorian distributor's brands as well as sharing of staff and offices in offering the new services.

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

Our 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 the Victorian distributors' alternative control services would not have a significant impact on the potential development of competition. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 discusses service classification.

### **2.4.2 Administrative costs**

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

### **2.4.3 Existing regulatory arrangements**

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

### **2.4.4 Desirability of consistency between regulatory arrangements**

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

We note that apart from the Victorian distributor's metering services which are currently 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.<sup>267</sup> In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that a material change in circumstances justifies departing from the formulae as set out in the F&A.<sup>268</sup>

Below are our price cap formulae that will apply to the Victorian distributors' alternative control services.

### Figure 2.2 Price cap formula to be applied to the Victorian distributors' public lighting and ancillary services (fee based)

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

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

Where:

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

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

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

$t$  is the regulatory year.

$\Delta CPI_t$  is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities<sup>269</sup> from the June quarter in year  $t-2$  to the June quarter in year  $t-1$ , calculated using the following method:

<sup>267</sup> NER, cl. 6.8.1(b)(2)(ii).

<sup>268</sup> NER, cl. 6.12.3(c1).

<sup>269</sup> 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.

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

divided by

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

minus one.

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

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

### **Figure 2.3 Price cap formula to be applied to the Victorian distributors' quoted services**

*Price = Labour + Contractor Services + Materials*

Where:

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

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities<sup>270</sup> from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

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<sup>270</sup> 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.

For example, for 2020–21, year t–2 is the June<sup>271</sup> quarter 2018 and year t–1 is the June 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* reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

### Figure 2.4 Revenue cap formula to be applied to the Victorian distributors' type 5, 6 and smart metering - regulated service

$$\begin{aligned}
 (1) \quad TARM_t &\geq \sum_{i=1}^n \sum_{j=1}^m P_t^{ij} q_t^{ij} && i=1,\dots,n \text{ and } j=1,\dots,m \text{ and } t=1,\dots,5 \\
 (2) \quad TARM_t &= AR_t + T_t + B_t + C_t && t = 1,2,\dots,5 \\
 (3) \quad AR_t &= AR_{t-1}(1 + \Delta CPI_t)(1 - X_t) && t = 1,2,\dots,5
 \end{aligned}$$

Where:

$TARM_t$  is the total annual revenue for annual metering charges in year t.

$P_t^{ij}$  is the price of component i of tariff j in year t.

$q_t^{ij}$  is the forecast quantity of component i of tariff j in year t.

$AR_t$  is the annual revenue requirement for year t.

$AR_{t-1}$  in 2021 is the annual smoothed revenue requirement in the Post Tax Revenue Model for the 2021 year in 2020 dollar value. After 2012 this is the  $AR_t$  from the previous year.

$T_t$  is the adjustments in year t for true-ups relating to the AMI-OIC.

<sup>271</sup> In our preliminary F&A, we mistakenly referenced the December quarter. We have rectified this error, referencing the June quarter as the most appropriate for Victorian distributors.

$B_t$  is the sum of annual adjustment factors in year t for the overs and unders account.

$C_t$  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.

$\Delta CPI_t$  is the percentage increase in the consumer price index. To be decided in the final decision.

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

### 3 Incentive schemes

This chapter sets out our position on the application of a range of incentive schemes, which apply to standard control services, to the Victorian distributors for the 2021–25 regulatory control period. At a high level, our position is to apply the:

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

The ECA submitted that it supports incentive schemes which ensure that investment is optimised based on consumers' expectations that not one more dollar is spent than is required and that new investments are not made one day earlier than necessary.<sup>272</sup>

#### 3.1 Service target performance incentive scheme

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

Our distribution STPIS<sup>273</sup> provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

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

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers<sup>274</sup> experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.<sup>275</sup>

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<sup>272</sup> Energy Consumer Australia, *Submission on Victorian Preliminary F&A 2021-25*, 19 November 2018, p .10.

<sup>273</sup> AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009. Currently under review, however the amendment process is not yet complete.

<sup>274</sup> Except where a jurisdictional electricity GSL requirement applies.

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

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

The Victorian distributors may propose to vary the application of the STPIS in their respective regulatory proposals.<sup>276</sup> We can accept or reject the proposed variation in our determination. Each year we will calculate the Victorian distributors' s-factor based on service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.<sup>277</sup> A distributor proposing a delay must provide in writing its reasons and justification as to why a delay will result in reduced price variations to customers.

Our STPIS currently applies to the Victorian distributors. The Victorian distributors are currently subject to a financial penalty or reward of  $\pm 5$  per cent. In the previous regulatory control period of 2016-20, we did not apply the GSL component as the Victorian distributors were subject to a Victorian jurisdictional GSL scheme under clause 6 of the ESCV Electricity Distribution Code.

## Submissions

The submission by the Department of Environment, Land, Water and Planning noted a number of initiatives - funded by Victorian consumers - that in its estimation will have the effect of significantly enhancing supply reliability throughout the network. Such initiatives include: an extensive roll out of Rapid Earth Fault Current Limiter (REFCL) equipment, and an estimated \$31.8 million AusNet Services is to receive to upgrade its Distributed Feeder Automation Systems. Its contention is that if STPIS targets are based on historical performance and do not consider the initiatives, distributors are likely to earn unwarranted

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<sup>275</sup> 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.

<sup>276</sup> AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.2.

<sup>277</sup> AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.5(d) and (e).

STPIS payments. As Victorian consumers have already paid for these reliability enhancing investments they are likely to be, in effect, paying twice.<sup>278</sup>

We understand the Department's concerns. We will take all factors that will affect supply reliability performance leading to departures from the historical performance level into account when establishing the STPIS performance targets in our determination.

### 3.1.1 AER's position

Our position is to continue to apply the national STPIS to the Victorian distributors in the 2021–25 regulatory control period. We propose to:

- set revenue at risk for each distributor within a range of  $\pm 5$  per cent
- segment the network according to the four STPIS feeder categories (CBD, urban, short rural and long rural as appropriate for each distributor) as per the scheme's definitions
- apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI, momentary interruption frequency index event or MAIFI and customer service (telephone answering) parameters
- set performance targets based on the distributor's average performance over the past five regulatory years
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the method and value of customer reliability (VCR) values as indicated in AEMO's 2014 Value of Customer Reliability Review final report, unless a more up-to-date value is available.

We will not apply the GSL component of the STIPS, as the Victorian distributors remain subject to a jurisdictional GSL scheme.

We are currently undertaking a review of the STPIS. One of the significant changes is to change the threshold definition of momentary interruption from the current less than one minute to less than three minutes. If the review is completed in time and subject to the necessary historical data being available, the new scheme will be applied to Victorian distributors for the 2021–25 regulatory control period.

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<sup>278</sup> DEWLP, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, p. 4.

### 3.1.2 AER's assessment approach

In deciding how to apply the current STPIS, we have considered the requirements of the NER. The NER sets out certain requirements in relation to developing and implementing a STPIS.<sup>279</sup> 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 and any regulatory obligations or requirements to which the distributor is subject.

#### Benefits to consumers

We must take into account the benefits to consumers of applying the STPIS. This includes:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the willingness of the customer or end user to pay for improved performance in the delivery of services
- balanced incentives
- the past performance of the distribution network
- any other incentives available to the distributor under the NER or the relevant distribution determination
- the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
- the possible effects of the schemes on incentives for the implementation of non-network alternatives.

We considered the benefits to consumers of applying the STPIS when we developed the scheme. These considerations are set out in our final decision for the distribution STPIS.<sup>280</sup>

### 3.1.3 Reasons for AER's position

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

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<sup>279</sup> NER, cl. 6.6.2(b).

<sup>280</sup> AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

## Jurisdictional obligations

In Victoria, the ESCV administers and monitors compliance with the distribution licence conditions set out in the Electricity Distribution Code. Our proposed approach does not intend to compromise the distributors' ability to comply with jurisdictional licence obligations or create duplication. We therefore propose not to apply the GSL component of our national STPIS while the GSL arrangements in Victoria remain in place.

## Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.<sup>281</sup>

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. VCR studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of unserved energy during a supply interruption.

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.<sup>282</sup>

In September 2014, AEMO completed analysis of the VCR across the NEM.<sup>283</sup> We stated in our final decision for the NSW distributors' 2015–19 regulatory period and our final F&A for NSW distributors' 2019–24 regulatory period,<sup>284</sup> that we will apply the latest value for VCR through the distribution determination in calculating the incentive rates. We consider the 2014 AEMO VIC VCR better reflects the willingness of customers to pay for the reliable supply of electricity in Victoria, unless a more up-to-date VCR is available at the time of our Final Decision. We consider that this approach is still appropriate.

We will calculate incentive rates at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

In December 2017, the COAG Energy Council submitted a rule change request that would allocate responsibility for updating and reviewing VCRs on an on-going basis to the AER. The AEMC published a consultation paper in May 2018.<sup>285</sup>

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<sup>281</sup> NER, cl. 6.6.2(b)(3)(vi).

<sup>282</sup> 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.

<sup>283</sup> AEMO, *Value of customer reliability review - Final report*, September 2014.

<sup>284</sup> AER, *Final framework and approach for Ausgrid, Endeavour and Essential Energy 2019-24*, July 2017, p. 61.

<sup>285</sup> See <https://www.aemc.gov.au/news-centre/media-releases/have-your-say-new-aer-role-determine-values-customer-reliability>.

In its request to replace the current F&A, AusNet services submitted that it is currently unclear whether the AER intends to produce updated VCRs that would apply to the 2021-25 regulatory control period. AusNet Services considers that we should specify in the F&A that the VCR that will be applied in the 2021-25 control period as the VCR is a fundamental input into AusNet Services' planning processes and any change will have material impacts on the scope and timing of planned work. AusNet Services submitted that it is critical that the AER provides time for AusNet Services to factor any updated value into its regulatory proposal and allow time for consultation with stakeholders, including the Customer Forum, on the impact of the value adopted for the regulatory proposal.<sup>286</sup>

We propose that the latest available VCR will be used to set the incentive rates under STPIS for our final decision for Victorian distributors for the 2021-25 regulatory control period. This means that we will apply the VCR values from the AEMO's 2014 analysis to the STPIS for the Victorian distribution determinations. Should the AER develop a new VCR prior to the release of the final decision, we will incorporate the latest available VCR in our final determination. We believe that this approach is preferable, as it reflects the most recent VCR values.

Our proposed approach is to apply the scheme standard level of revenue at risk for the Victorian distributors at  $\pm 5$  per cent as we do not consider that a lower than scheme standard level would fully achieve the intended outcomes of the STPIS.

## Balanced incentives

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

## Defining performance targets

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

The NER requires us to consider past performance of the distributor's network in developing and implementing the STPIS.<sup>287</sup> Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.<sup>288</sup> Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in a specific year to make future targets less onerous.

Under this approach, distributors will only receive a financial reward for achieving reliability improvements. More importantly, a distributor can only retain the reward if it can maintain the reliability improvements. This is because once an improvement is made, the benchmark

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<sup>286</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace framework and approach*, 30 April 2018, p. 6.

<sup>287</sup> NER, cl. 6.6.2(b)(3)(iii).

<sup>288</sup> Subject to any modifications required under cl. 3.2.1(a) and (b) of the national STPIS.

performance targets will be adjusted to reflect the improved level of performance. If it allows reliability to decline in the future, the distributor will be penalised. Our STPIS limits variability in penalties and rewards caused by circumstances outside the distributor's control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance.

### **Interactions with our other incentive schemes**

In applying the STPIS, we must consider any other incentives available to the distributor under the NER or relevant distribution determination.<sup>289</sup> In Victoria, the STPIS will interact with our expenditure and demand management incentive schemes.

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

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.<sup>290</sup>

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

## **3.2 Efficiency benefit sharing scheme**

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

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

This section sets out our position and reasons on how we intend to apply the EBSS to the Victorian distributors in the 2021–25 regulatory control period.

### **3.2.1 AER's position**

We intend to apply the EBSS to the Victorian distributors in the 2021–25 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers.<sup>291</sup> This will occur only if the opex forecast for the following

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<sup>289</sup> NER, cl. 6.6.2(b)(3)(iv).

<sup>290</sup> Included in the distributor's approved forecast capex for the next period.

<sup>291</sup> NER, cl. 6.5.8(a).

period is based on the distributors' revealed costs. Our distribution determinations for the Victorian distributors for the 2021–25 regulatory control period will specify if and how we will apply the EBSS.<sup>292</sup>

### 3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between a network service provider and network users.<sup>293</sup> We must also have regard to the following factors in developing and implementing the EBSS:<sup>294</sup>

- 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 position

The EBSS currently applies to the Victorian distributors in the 2016–20 regulatory control period.

We will decide if and how we will apply the EBSS to the Victorian distributors in the 2021–25 regulatory control period in our determinations. The decision to apply the EBSS will depend on whether we expect to use the distributors' revealed costs in the 2021–25 regulatory control period to forecast opex in the following period.

#### Why we would apply the EBSS

We will only apply the EBSS in the 2021–25 regulatory control period if we expect we will use a revealed cost forecasting approach to forecast opex for the 2026–30 regulatory control period.

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

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

293 NER, cl. 6.5.8(a).

294 NER, cl. 6.5.8(c).

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

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

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

In implementing the EBSS, we also consider any incentives distributors may have to capitalise expenditure.<sup>295</sup> Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. If the CESS and EBSS are both applied, these incentives will be relatively balanced. We discuss the CESS further in section 3.3.

We also consider the effects of implementing the EBSS on incentives for non-network alternatives<sup>296</sup> (which are generally opex rather than capex). When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way, the distributor will receive a net reward for implementing the non-network alternative.<sup>297</sup> Non-network alternatives and the demand management incentives, including the new DMIS, are discussed further in section 3.4.

We are currently reviewing the interaction of operating expenditure forecasts, the EBSS and the new DMIS. We will seek to confirm our position as part of the regulatory determination process, but note that in implementing the EBSS and DMIS we will seek to provide balanced opex and capex incentives that encourage a distributor to identify and undertake efficient demand management options.

## Why we would not apply the EBSS

We will not apply the EBSS if it is likely we will *not* use a revealed cost forecasting approach to forecast opex for the 2026–30 regulatory control period.

If we apply the EBSS but do not forecast opex using revealed costs, a distributor could in theory receive an EBSS reward for efficiency gains (at a cost to consumers), but consumers would not benefit through a lower revealed cost forecast. If the distributor expects this, it has an incentive to increase its EBSS carryover by underspending in its base year, knowing the

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<sup>295</sup> NER, cl. 6.5.8(c)(4).

<sup>296</sup> NER, cl. 6.5.8(c)(5).

<sup>297</sup> When the distributor spends more on opex it incurs approximately 30 per cent of that increase as a result of the EBSS. At the same time it retains 30 per cent of the capex decrease through the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward.

underspend will not reduce its opex forecast.<sup>298</sup> Consumers would pay the EBSS reward but not receive a share of the underspend and would be worse off. This outcome is contrary to the NER, which requires that the EBSS must provide for a fair sharing of efficiency gains and losses between a distributor and consumers.<sup>299</sup>

If a distributor's revealed costs in the 2021–25 regulatory control period are materially higher than the opex incurred by a benchmark efficient distributor, we will be unlikely to use revealed costs to forecast opex for the 2026–30 regulatory control period. In which case, we will be unlikely to apply the EBSS.

### 3.3 Capital expenditure sharing scheme

The CESS provides incentives for distributors to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. Consumers benefit from improved efficiency through lower network prices in the future. This section sets out our proposed approach and reasons for our intention to apply version 1 (dated 29 November 2013) of the CESS to the distributors.

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend amount for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts.<sup>300</sup> 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.

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<sup>298</sup> In our explanatory statement to the EBSS, we discuss why we should exclude the expenditure categories not forecast using a single year revealed cost forecasting method from the EBSS to prevent network users being worse off. AER, *Explanatory statement - efficiency benefit sharing scheme*, November 2013, pp. 18-19.

<sup>299</sup> NER, cl'6.5.8(a).

<sup>300</sup> 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.

In its submission, the Department of Environment, Land, Water and Planning said that its preference is that the CESS does not apply to Victorian distributors during the 2021-25 regulatory period. This is due to the incentive for distributors to over-forecast capital expenditure and then underspend relative to forecasts in order to profit from the CESS. As evidence, the Department pointed to underspends by Victorian distributors in the first two years of the CESS.<sup>301</sup>

We note it is important to remember that the incentive to over forecast capex, and then underspend relative to the capex allowance would exist even if we did not apply the CESS. The ex-ante regulatory framework where a distributors' capex allowance is set at the beginning of a regulatory control period and there is financing benefit if they do not spend the capex allowance provides this incentive. The incentive is greater at the start of the period given the longer timeframes to realise the financing benefit. The application of the CESS provides distributors with a constant incentive to underspend and realise efficiencies, rather than a declining incentive over the regulatory control period. We consider any additional incentive provided by the CESS in the first two years of a control period is small. Consequently, we do not consider that identifying an underspend in the first two years of the control period provides a strong reason to not apply the CESS in future periods. An underspend could also be the result of the incentive framework working, rather than forecasting error.

The result of not applying the CESS would be imbalanced capex and opex incentives. This could distort the distributor's' incentive to make efficient choices between capex and opex. At this stage, we would like to see how each of the networks responds to the CESS before we consider whether it should not be applied, or whether it should be modified.

### 3.3.1 AER's position

Our final position is to apply the CESS, as set out in our capex incentives guideline,<sup>302</sup> to the Victorian distributors in each regulatory year of the 2021–25 regulatory control period.

### 3.3.2 AER's assessment approach

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:<sup>303</sup>

- make that decision in a manner that contributes to the capex incentive objective set out in the NER<sup>304</sup>
- consider the CESS principles,<sup>305</sup> capex objectives,<sup>306</sup> other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

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<sup>301</sup> DEWLP, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, p. 2.

<sup>302</sup> AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 5–9.

<sup>303</sup> NER, cl. 6.5.8A(e).

<sup>304</sup> NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

<sup>305</sup> NER, cl.6.5.8A(c).

<sup>306</sup> NER, cl. 6.5.7(a).

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 position

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

The Victorian distributors are currently subject to a CESS. As part of our Better Regulation program, we consulted on and published version 1 of the capex incentives guideline, which sets out the CESS.<sup>307</sup> The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.<sup>308</sup> 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.

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

Without a CESS, the incentive for a distributor to spend less than its forecast capex declines throughout the period.<sup>309</sup> Because of this, a distributor may choose to spend capex earlier, or spend on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

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

In addition, when the CESS, EBSS and STPIS apply to a distributor, incentives for opex, capex and service performance are balanced. This encourages a distributor to make efficient

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<sup>307</sup> AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 5–9.

<sup>308</sup> AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

<sup>309</sup> As the end of the regulatory period approaches, the time available for the distributor to retain any savings gets shorter. So the earlier a distributor incurs an underspend in the regulatory period, the greater its reward will be.

decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

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

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

### **3.4 Demand management incentive scheme and demand management innovation allowance mechanism**

We established a new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM) in December 2017.<sup>310</sup> It is intended that the new DMIS and DMIAM are to apply to the Victorian distributors in the 2021–25 regulatory control period.

The DMIS is intended to encourage distribution businesses to find lower cost solutions to investing in network solutions. The incentive scheme achieves this by encouraging distribution businesses to undertake efficient expenditure on non-network options relating to demand management.

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

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<sup>310</sup> <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>

### 3.4.1 AER's position

We intend to apply our new DMIS and DMIAM as published by us in December 2017 to apply to the Victorian distributors in the 2021–25 regulatory control period.

### 3.4.2 Reasons for AER's position

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

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

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

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

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

- Selecting efficient projects that deliver the most value to consumers when solving network constraints, regardless of whether these projects constitute a demand-side or supply-side solution.
- Asking third parties to propose demand management solutions, and forming contracts with parties that propose solutions that deliver the most value to consumers.

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

We believe that the DMIS, supported by the DMIAM, will provide long-term benefit to customers.

### 3.4.3 AER's assessment approach to the DMIS

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

## 3.5 Victoria F-factor scheme

On 22 December 2016, the Victorian Government published the “f-factor scheme order 2016” (the 2016 Order), which revoked the previous 2011 f-factor scheme Order. Instead of the previous calendar year measurement method, the new f-factor scheme now measures fire starts on a financial year basis to coincide with the fire season.

The new f-factor scheme targets incentives towards fire ignitions that pose the greatest risk of harm via ignition risk units (IRUs). The key difference between the new and the current scheme is that each fire is weighted by a “location factor” and a “fire risk (timing) factor”. By applying these weighting factors to each fire, the fire will have a score called an "IRU". These factors and their inputs are all prescribed by the Order.

In its submission the Department of Environment, Land, Water and Planning noted that the Victorian Government intends to publish updated IRUs for the financial year 2020-21 and onwards, prior to the commencement of the next regulatory period.<sup>311</sup> We will continue to use the latest available IRUs as the basis for our calculations.

### 3.5.1 AER's position

We intend to continue to apply the Victoria f-factor scheme as set out in the 2016 Order to the Victorian distributors in the 2021–25 regulatory control period.

The IRU targets for relevant financial years have been set by the 2016 Order.<sup>312</sup> If the Order remains unchanged,<sup>313</sup> the IRU target for each financial year of the forthcoming period are:

AusNet	CitiPower	Jemena	Powercor	United Energy
221.1	3.4	9.7	412.8	22.3

Source: Clause 10 (1), the Order.

### 3.5.2 Reasons for AER's position

The new f-factor scheme seeks to incentivise better alignment between the bushfire risk reduction practices and priorities of the distribution businesses and the bushfire risk exposure of the Victorian community posed by the distribution network.<sup>314</sup>

<sup>311</sup> DEWLP, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 29 October 2018, p. 5.

<sup>312</sup> Under clause 10(3) of the Order.

<sup>313</sup> Under clause 10(2) of the Order, the Minister may modify the IRU targets by modifying the Order.

<sup>314</sup> Victorian Department of Environment Land Water and Planning, *f-factor Incentive Scheme: Regulatory Impact Statement*,

The new scheme will still provide a symmetrical scheme in terms of rewards or penalties - a revenue adjustment - with respect to the historical performance. However, the benchmark targets for fire starts will be measured differently as will the calculation of reward or penalty amounts.

### 3.5.3 AER's assessment approach

Under the new scheme, the revenue adjustment is to be arrived at by applying an incentive rate to an IRU target subtracted for pass performance in the form of an IRU amount.<sup>315</sup> The f-factor scheme requires the AER to determine the IRU amount.<sup>316</sup> The incentive rate and IRU target are prescribed.<sup>317</sup>

Under the new scheme, distributors will prepare a fire start report each year. Energy Safe Victoria (ESV) will then review this and verify the accuracy of the fire start reports. After this process, ESV will advise the AER on whether the reports are accurate; and if they are not accurate, the relevant IRU scores. We will then determine the appropriate rewards or penalties that may apply for each distributor in accordance with the incentive rate prescribed by the Order.

## 3.6 Small scale incentive scheme

The Victorian distributors have expressed an intention to request the introduction of a small-scale incentive scheme (SSIS) to substitute some aspects of the STPIS. Some distributors have noted that, the existing incentive framework has not kept pace with changes in the way they communicate with their customers, and the ways in which their customers communicate with them.<sup>318</sup> Others have noted that the customer service parameters of the STPIS do not adequately reflect current needs and preferences of clients.<sup>319</sup> Distributors have suggested that this could be addressed by introducing a Small Scale Incentive Scheme (SSIS), which may replace all or part of the telephone answering parameter to better align with the modern customer experience.<sup>320</sup>

AusNet Services has proposed the introduction of a Customer Service Incentive Scheme and continues to examine the substance and breadth of its proposed scheme with the Customer Forum.<sup>321</sup> Jemena and CitiPower/Powercor/United Energy later expressed their intention, both informally and via submission to the preliminary F&A, to propose similar

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October 2016, p. 15.

<sup>315</sup> Cl. 9, *National Electricity (Victoria) Act 20005, F-Factor Scheme Order 2016*, G51, 22 December 2016.

<sup>316</sup> Cl. 11, *National Electricity (Victoria) Act 20005, F-Factor Scheme Order 2016*, G51, 22 December 2016.

<sup>317</sup> See cl. 9(4)(ii) and 9(4)(iii), *National Electricity (Victoria) Act 20005, F-Factor Scheme Order 2016*, G51, 22 December 2016.

<sup>318</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 8 and AusNet Services, Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3.

<sup>319</sup> AusNet Services, *Customer Experience: Revised negotiating position for the Customer Forum*, 1 October 2018, p.14.

<sup>320</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 8, CitiPower, Powercor and United Energy, Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 6, AusNet Services, Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3.

<sup>321</sup> AusNet Services, *Customer Experience: Revised negotiating position for the Customer Forum*, 1 October 2018, p.14

incentive schemes. However, they will first engage with stakeholders and the CCP to gauge customer support for the proposal.<sup>322</sup> CCP 17 submitted that it supports the concept of the small-scale incentive scheme and considers it a useful mechanism to encourage innovation'.<sup>323</sup>

The NER allows us to develop a SSIS providing us the flexibility to innovate by providing for incentives that are not already covered by the existing incentive schemes and as a means to test such schemes to ensure that their potential impact is understood before full implementation.<sup>324</sup> For example, a SSIS can provide rewards for distributors who engage more effectively with consumers.<sup>325</sup>

### 3.6.1 AER's position

In 2019, we will continue to consider whether to develop a SSIS to apply in the 2021-25 regulatory control period. We note that AusNet Services' submission quoted observations made by the AEMC in their final determination which acknowledged the need to balance the proposed revenue at risk, so that it was significant enough to allow the AER to understand how the scheme operated, but not so high that there would be a significant impact on a distributor if the scheme did not operate as intended.<sup>326</sup> We also note that despite this, the AEMC still considered it necessary that the AER be able to carry out paper trials as part of its discretion.<sup>327</sup>

### 3.6.2 Reasons for position

We consider that the development of a SSIS could potentially benefit customers and we are open to Victorian distributors proposing such a scheme. We are considering whether a customer service incentive scheme is necessary and what form such an incentive may take. However, any scheme would need to be consistent with the requirements of clause 6.6.4 of the NER, particularly those matters listed at clause 6.6.4(b).<sup>328</sup> Furthermore, any scheme developed and published by the AER would need to have complied with the distribution consultation procedures.

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<sup>322</sup> Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 8, CitiPower, Powercor and United Energy, Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 6.

<sup>323</sup> CCP17, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 12 November 2018, p. 11.

<sup>324</sup> AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November 2012, pp. 13, 212.

<sup>325</sup> AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November 2012, p. 212.

<sup>326</sup> AusNet Services, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3, which references AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November 2012, pp. 13, 197.

<sup>327</sup> AusNet Services, Jemena, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 3.

<sup>328</sup> NER, cl. 6.6.4.

## 4 Expenditure forecast assessment guideline

This chapter sets out our intention to apply our expenditure forecast assessment guideline (the EFA guideline)<sup>329</sup> including the information requirements applicable to the Victorian distributors for the 2021–25 regulatory control period. The EFA guideline sets out our expenditure forecast assessment approach developed and consulted upon during the Better Regulation program. It outlines the assessment techniques we will use to assess a distributor's proposed expenditure forecasts, and the information we require from the distributor.

The EFA guideline uses a nationally consistent reporting framework that allows us to compare the relative efficiencies of distributors and decide on efficient expenditure forecasts. The NER requires Victorian electricity distributors to advise us by 31 December 2018 of the methodology they propose to use to prepare their forecasts.<sup>330</sup> In the final F&A, we must advise whether we will deviate from the EFA guideline.<sup>331</sup> This will provide clarity on how we will apply the EFA guideline and the information the Victorian electricity distributors should include in their regulatory proposals. This contributes to an open and transparent process and makes our assessment of expenditure forecasts more predictable. The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of the expenditure forecasts that distributors include in their regulatory proposals. We intend to have regard to the assessment tools set out in the guideline. The tool kit includes:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.<sup>332</sup>

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

For opex, in most cases we take a base-step-trend approach to assessing forecast expenditure and in this context use top down economic benchmarking tools to determine the reasonableness of the forecast rather than a bottom-up assessment approach. However, in

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<sup>329</sup> We were required to develop the EFA guideline under clauses 6.4.5 and 11.53.4 of the NER. We published the guideline on 29 November 2013. It can be located at [www.aer.gov.au/node/18864](http://www.aer.gov.au/node/18864).

<sup>330</sup> NER, cl. 6.8.1A(b)(1).

<sup>331</sup> NER, cl. 6.8.1(b)(2)(viii).

<sup>332</sup> AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

exercising our judgement, we may use any analytical tool at our disposal, including assessing individual elements of the forecast using a bottom-up approach.

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

In the context of continuously improving economic benchmarking, we are currently reviewing and refining our analysis of operating environment factors in consultation with industry and other interested parties. The review will be finalised in 2018.<sup>333</sup> We will then seek to implement any recommended improvements from that process in our annual benchmarking and regulatory determination processes.

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<sup>333</sup> More information is available at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-operating-environment-factors-for-distribution-network-service-providers>.

## 5 Depreciation

As part of the process of rolling forward a distributor's RAB to the start of the next regulatory control period, we update the RAB for actual capex incurred during the current regulatory control period and adjust for depreciation. This chapter sets out our approach on the form of depreciation to be used when the Victorian distributors' RABs are rolled forward to the commencement of the 2026–30 regulatory control period. To provide further clarity, in this chapter, when we reference the roll forward of the RAB, it is in the context of standard control services. Alternative control services are treated differently.<sup>334</sup>

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

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

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

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.<sup>335</sup> In summary:

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

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for the distributor to underspend capex on shorter lived assets compared to longer lived assets as this will lead to a relatively larger increase in the RAB. Use of forecast depreciation, on the other hand,

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<sup>334</sup> For example, metering and public lighting RABs, are classified as providing alternative control services for which we consider actual depreciation, (that is based on actual capex), is the most appropriate approach for rolling forward these respective RABs to the commencement of the 2026-30 regulatory control period.

<sup>335</sup> AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

leads to the same incentive for capex regardless of asset lives. This is because using forecast depreciation does not affect the distributor's incentive on capex as the distributor does not lose the full cost of any overspend and is not able to keep all the benefits of any underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

## 5.1 AER's position

Our position is to continue using the forecast depreciation approach to establish the RAB at the commencement of the 2026–30 regulatory control period for the Victorian distributors. We consider this approach will provide sufficient incentives for the Victorian distributors to achieve capex efficiency gains over the 2021–25 regulatory control period.

## 5.2 AER's assessment approach

In our distribution determination, we have to decide whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.<sup>336</sup>

We set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.<sup>337</sup> Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:<sup>338</sup>

- 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 position

Consistent with our capex incentives guideline, we propose to continue using the forecast depreciation approach to establish the RAB for the Victorian distributors at the commencement of the 2026–30 regulatory control period. We note AusNet Services and Jemena proposed this approach in their request to replace the current F&A.<sup>339</sup> 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.<sup>340</sup>

Our approach is to apply forecast depreciation except where:

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<sup>336</sup> NER, cl. S6.2.2B.

<sup>337</sup> NER, cl. 6.4A(b)(3).

<sup>338</sup> NER, cl. S6.2.2B.

<sup>339</sup> AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April, p. 6; Jemena Electricity Networks (Vic) Ltd, *Request for a replacement Framework and Approach*, 30 April 2018, p. 9.

<sup>340</sup> 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 distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher powered incentive.

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

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

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

The opening RAB at the commencement of the 2021–25 regulatory control period will be established using forecast depreciation, as stated in our previous determination that applies to the Victorian distributors for the 2016–20 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2026–30 regulatory control period therefore maintains the current approach. The Victorian distributors are currently subject to a CESS and we propose to continue applying the CESS in the 2021–25 regulatory control period. We discuss this in section 3.3.

For the Victorian distributors, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.<sup>341</sup> 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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<sup>341</sup> AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19 and 20–21.

## Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.<sup>342</sup>

1. 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, electricity 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.<sup>343</sup>
2. 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)<sup>344</sup>
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)<sup>345</sup>
4. any other relevant factor.<sup>346</sup>

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.<sup>347</sup>

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<sup>342</sup> NER, cl. 6.2.1(c).

<sup>343</sup> NEL, s. 2F.

<sup>344</sup> NER, cl. 6.2.1(c)(2).

<sup>345</sup> NER, cl. 6.2.1(c)(3).

<sup>346</sup> NER, cl. 6.2.1(c)(4).

<sup>347</sup> NER, cl. 6.2.2(c).

1. the potential for development of competition in the relevant market and how the classification might influence that potential
2. the possible effects of the classification on administrative costs of us, the distributor and users or potential users
3. the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
4. the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
5. the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
6. any other relevant factor.<sup>348</sup>

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.

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<sup>348</sup> NER, cl. 6.2.2(c).

## Appendix B: Proposed service classification of Victorian distribution services 2021–25<sup>349</sup>

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
Common distribution service - use of the distribution network for the conveyance/flow of electricity (including the services relating to network integrity)			
Common distribution service (formerly 'network services')	<p>The suite of activities that includes, but is not limited to, the following:</p> <ul style="list-style-type: none"> <li>the planning, design, repair, maintenance, construction, and operation of the distribution network</li> <li>works to fix damage to the network (including recoverable works caused by a customer or third party)</li> <li>support for another network during an emergency event</li> <li>procurement and provision of network demand management activities for distribution or system reliability, efficiency or security purposes</li> <li>activities related to 'shared asset facilitation' of distributor assets<sup>350</sup></li> </ul>	Standard control	Standard control

<sup>349</sup> The examples and activities listed in the 'Further description' column are not intended to be an exhaustive list and some distributors may not offer all activities listed. Rather the examples provide a sufficient indication of the types of activities captured by the service.

<sup>350</sup> Revenue for these services is charged to the relevant third party and is treated in accordance with the shared asset guideline. 'Shared asset facilitation' refers to administrative costs. It does not refer to the costs associated with providing the unregulated service itself.

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	<ul style="list-style-type: none"> <li>• emergency disconnect for safety reasons and work conducted to restore a failed component of the distribution system to an operational state upon investigating a customer outage</li> <li>• establishment and maintenance of National Metering Identifiers (NMIs) in market and/or network billing systems, and other market and regulatory obligations</li> <li>• ongoing inspection of private electrical networks (not part of the shared network) required under legislation for safety reasons<sup>351</sup></li> <li>• supply abolishment of basic connection<sup>352</sup></li> <li>• customer safety information, e.g. 'dial before you dig' services</li> <li>• Bulk supply point metering - activities relating to monitoring the flow of electricity through the distribution network.</li> <li>• Third party initiated network asset relocations/re-arrangements under ESCV Guideline 14. <sup>353</sup></li> <li>• Transmission network support</li> </ul>		

<sup>351</sup> The Victorian Electricity Safety Act 1998, clause 113F, requires Vic DNSPs to inspect overhead private electric lines.

<sup>352</sup> This service is classified as Standard Control Services under the 2016-20 Determination for public safety reasons. Victorian DNSPs wish to continue with the classification.

<sup>353</sup> This classification applies where a customer contribution is calculated and applied in accordance with Essential Services Commission (ESCV) Guideline 14 or where a customer contribution is calculated and applied in accordance with any other relevant Victorian legislation or regulation, including regulations made under the National Electricity (Victoria) Act, 2005. The party requesting such works under this classification must pay the net cost of the works, subject to any rebates specified in Guideline 14 or by any other relevant Victorian legislation or regulation.

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
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Network ancillary services – customer and third party initiated services related to common distribution services

Access permits, oversight and facilitation	<p>Activities include:</p> <ul style="list-style-type: none"> <li>• a distributor issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage</li> <li>• a distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space</li> <li>• a distributor providing access to switch rooms, substations and other network equipment to a non-Local Network Service Provider 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.</li> <li>• specialist services (which may involve design related activities and oversight/inspections of works) where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets</li> <li>• facilitation of generator connection and operation of the network</li> <li>• facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets.</li> </ul>	Not classified	Alternative control
Sale of approved materials or equipment	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network.	Not classified	Alternative control

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
Notices of arrangement and completion notices	<p>Examples include:</p> <ul style="list-style-type: none"> <li>• Work of an administrative nature where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This includes: receiving and checking subdivision plans, 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.</li> <li>• Provision of a completion notice (other than a notice of arrangement). This applies where the real estate developer requests the distributor to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to meet contractual undertakings.</li> </ul>	Not classified	Alternative control
Network related property services	<p>Activities include:</p> <ul style="list-style-type: none"> <li>• Network related property services such as property tenure services relating to providing advice on, or obtaining: deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with a connection or relocation.</li> <li>• Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.</li> </ul>	Not classified	Alternative control

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
Network safety services	<p>Examples include:</p> <ul style="list-style-type: none"> <li>• provision of traffic control and safety observer services by the distributor where required</li> <li>• fitting of tiger tails, possum guards, and aerial markers</li> <li>• high load escorts.</li> <li>• site visit relating to location of underground cables/assets</li> <li>• Third party request for de-energising wires for safe approach</li> </ul>	Alternative control	Alternative control
Planned Interruption – customer requested amendment	<p>Examples include:</p> <ul style="list-style-type: none"> <li>• where the customer requests to move a distributor planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours</li> </ul>	Not classified	Alternative control
Customer requested supply outage	<p>Examples include:</p> <ul style="list-style-type: none"> <li>• customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer’s assets, work close to or for safe approach, which impacts other networks users).</li> </ul>	Not classified	Alternative control
Inspection and auditing services	<p>Activities include:</p> <ul style="list-style-type: none"> <li>• inspection and reinspection by a distributor, of gifted assets or assets that have been installed or relocated by a third party</li> <li>• investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider</li> </ul>	Alternative control	Alternative control

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	<p>due to unsafe practices or substandard workmanship</p> <ul style="list-style-type: none"> <li>auditing of a third party service provider’s work practices in the field</li> <li>re-test at a customer’s installation, where the installation fails the initial test and cannot be connected.</li> </ul>		
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor’s network. Such learning outcomes may include those necessary to demonstrate competency in the distributor’s electrical safety rules, to hold an access authority on the distributor’s network and to carry out switching on the distributor’s network. Examples of training might include high voltage training, protection training or working near power lines training.	Not classified	Alternative control
Authorisation and approval of third party service providers design, work and materials	<p>Activities include:</p> <ul style="list-style-type: none"> <li>authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party service providers (excludes training services)</li> <li>acceptance of third party designs and works</li> <li>assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor’s approved materials list</li> </ul>	Alternative control	Alternative control
Security lights	Provision, installation, operation, and maintenance of equipment mounted on	Not classified	Alternative control

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	distribution equipment used for security services, e.g. nightwatchman lights. Note: excludes connection services.		
Customer requested provision of electricity network data	Data requests by customers or third parties including requests for the provision of electricity network data or consumption data outside of legislative obligations.	Not classified	Alternative control
Third party funded network alterations or other improvements	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to be installed on the shared distribution network. This does not relate to upstream distribution network augmentation.	Alternative control	Alternative control
Customer initiated network asset relocations/re-arrangements	Relocation of assets that form part of the distribution network in circumstances where the relocation was initiated by a third party (including a customer), not provided under ESCV Guideline 14.	Alternative control	Alternative control
Community network upgrades	Collective customer requested network enhancement. Activities related to community requests to augment the network to enable higher PV exports.	Not Classified	Alternative Control
Metering services - activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters)			
Type 1 to 4 metering services	Type 1 to 4 metering installations <sup>354</sup> and supporting services are competitively available.	Unregulated	Unregulated

<sup>354</sup> Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
Type 5 and 6 (inc. smart metering) services where the distributor remains responsible	<p>Includes:</p> <ul style="list-style-type: none"> <li>• Recovery of the cost of type 5 and 6 metering equipment<sup>355</sup> including communications network (including meters with internally integrated load control devices).</li> <li>• Testing, inspecting, investigating, maintaining or altering existing type 5 or 6 metering installations or instrument transformers.</li> <li>• Quarterly or other regular reading of a metering installation.</li> <li>• Metering data services that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of relevant NMI Standing Data in accordance with the NER.</li> </ul>	Alternative control	Alternative control
Auxiliary metering services (type 5 to 7 including smart metering) where the distributor remains responsible	<p>Activities include:</p> <ul style="list-style-type: none"> <li>• requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation</li> <li>• testing and maintenance of instrument transformers for type 5 and 6 metering purposes</li> <li>• Non-standard metering services for Type 5 to 7 meters and any other meter types introduced.</li> </ul>	Alternative control	Alternative control

<sup>355</sup> Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	<ul style="list-style-type: none"> <li>works to re-seal a type 5 or 6 meter due to customer or third party action (e.g. by having electrical work done on site)</li> <li>change distributor load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement.</li> <li>Remote de-energisation and re-energisation</li> <li>Remote meter configuration</li> <li>Field based special meter read</li> <li>Office based special meter read</li> <li>Metering exit services</li> </ul>		
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Alternative control	Alternative control
Connection services <sup>356</sup> - services relating to the electrical or physical connection of a customer to the network			
Basic connection services	Means a <i>connection service</i> <sup>357</sup> related to a <i>connection</i> (or a proposed	Alternative control	Alternative control

<sup>356</sup> When discussing connections, we must consider how connection policies and chapter 5A of the NER impact the regulation of connection services. For this reason, we will not be able to completely address the classification of connection services in the classification guideline.

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	<p><i>connection</i>) between a <i>distribution system</i> and a <i>retail customer's</i> premises (excluding a non-registered <i>embedded generator's</i> premises) in the following circumstances:</p> <p>(a) either:</p> <ol style="list-style-type: none"> <li>1. the <i>retail customer</i> is typical of a significant class of <i>retail customers</i> who have sought, or are likely to seek, the service; or</li> <li>2. the <i>retail customer</i> is, or proposes to become, a <i>micro embedded generator</i>; and</li> </ol> <p>(b) the provision of the service involves minimal or no <i>augmentation</i> of the <i>distribution network</i>; and</p> <p>(c) a <i>model standing offer</i> has been approved by the AER for providing that service as a <i>basic connection service</i>.</p>		
Standard connection service	Means a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by the AER.	Standard control	Standard control
Negotiated connection	<p>Means a connection service (other than a basic connection service) for which a DNSP provides a connection offer for a negotiated connection contract.</p> <p>This includes connections under Chapter 5 of the NER.</p>	Standard control	Standard control

<sup>357</sup> Italics denotes definitions in Chapter 5A of the NER.

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
Connection application and management services	<ul style="list-style-type: none"> <li>• Connection application related services</li> <li>• Works initiated by a customer or retailer that are specific to the connection point. This includes, but is not limited to:</li> <li>• field based de-energisation<sup>358</sup> and re-energisation</li> <li>• Non basic supply abolishment or reposition non-basic connection</li> <li>• Temporary connections (e.g. for builder's supply, fetes etc.)</li> <li>• overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. because of a point of attachment relocation). No material change to load</li> <li>• protection and power quality assessment</li> <li>• supply enhancement (e.g. upgrade from single phase to three phase)</li> <li>• customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g. change protection settings)</li> <li>• upgrade from overhead to underground service</li> <li>• rectification of illegal connections or damage to overhead or underground service cables</li> <li>• calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user</li> </ul>	Alternative control	Alternative control

<sup>358</sup> De-energisation services related to business as usual activities and de-energisation services that may relate to changing over meter types

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	<p>with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER</p> <ul style="list-style-type: none"> <li>• calculation of site specific loss factors when required under the NER</li> <li>• power factor correction</li> <li>• Embedded network management</li> <li>• assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers</li> <li>• processing preliminary enquiries requiring site specific or written responses</li> <li>• undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants</li> <li>• liaising with groups representing multiple connecting parties (e.g. community group upgrades)</li> <li>• site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects</li> <li>• registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER.</li> </ul>		
Enhanced connection services	Other or enhanced connection services provided at the request of a customer or third party that include those that are:	Alternative control/ negotiated/ Not classified	Alternative control

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
	<ul style="list-style-type: none"> <li>provided with higher quality of reliability standards, or lower quality of reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance.</li> <li>in excess of levels of service or plant ratings required to be provided by the distributor</li> </ul>		
Public lighting - lighting services provided in connection with a distribution network			
Public lighting	<ul style="list-style-type: none"> <li>Operation, maintenance, repair and replacement public lighting services</li> <li>Alteration and relocation of public lighting assets</li> <li>New public lighting services incl. greenfield sites &amp; new light types (distributor provided)</li> <li>Provision, construction and maintenance of emerging public lighting technology.</li> </ul>	Alternative control/ negotiated	Alternative control

## Appendix C: Summary of submissions, and our response, not covered within the Victorian F&A

Received From	Key points of submission	AER response
Consumer Challenge Panel (CCP 17)	CCP 17 encouraged the AER to undertake an urgent review of the Shared Asset Guideline to ensure that customers benefit from the use of regulated distribution assets to earn unregulated income.	A review of the Shared Asset Guideline is currently on the AER's forward work program and will be attended to as resourcing and workflows allow.
Consumer Challenge Panel (CCP 17)	CCP 17 suggested that analysis be undertaken to determine whether net benefit arise from harmonising Victorian metering arrangements with the rest of the NEM i.e. implementing metering contestability.	Harmonising metering contestability with the rest of the NEM is a jurisdictional prerogative.
The Department of Environment, Land, Water and Planning (DELWP)	<p>The Department urged us to consider in our revenue determination:</p> <ul style="list-style-type: none"> <li>• Additional smart inverter technologies required to effectively enable the higher uptake of DER while maintaining system security and reliability by giving distributors greater visibility and control for managing voltage;</li> <li>• The information available from smart meters and AEMO's distributed energy register which may enable better management of distribution system; and</li> <li>• The co-location of additional energy storage devices in congested parts of the network.</li> </ul>	<p>These issues should be considered as part of the determination process. We encourage the Department to submit a submission on the regulatory proposals of the network businesses during the consultation period. There will also be an opportunity to make submissions on our draft decision due in March 2020.</p>

Received From	Key points of submission	AER response
DELWP	<b>Timely electricity connections to new developments</b> - The distributors are considering "fast-tracked audit services", designed to provide appropriate pricing of connection audit services, as possible alternative control services. This forms part of the Distributor's Service Improvement commitment with the Victorian Government. The aim of which is to achieve timely electricity connections to new developments.	This activity will enable distributors to offer a fast-tracked connection process to customers who apply. However, it is not a new service that is considered within the classification process in the F&A. Distributors are able to propose activities as line items within the appropriate grouping, along with the associated prices in their pricing proposals. We suggest this would be a line item within the Auxiliary metering services grouping, submitted as part of the regulatory proposal. Distributors have indicated they are looking to provide these services. <sup>359</sup>
EnergyAustralia	"Recoverable works to fix damage to the network caused by a customer or third party – damage following a person's act or omission" have been classified as direct control. As this applies to Type 5 and 6 meters owned by the distributor and not contestable metering, appropriate consideration should be given to cost recovery for contestable meters that have been damaged in the process.	Cost recovery for third party, or other, damage to contestable meters sits with the relevant retailer or metering coordinator.
EnergyAustralia	Consideration should be given to the AER providing some level of regulatory oversight of the gifting of Current Transformer (CT) load control device assets and their subsequent cost recovery.	While we do not address CT load devices specifically in the F&A, we note that they are generally built into metering equipment and are discarded when the meter is exchanged. Distributors are able to recover the costs of type 5 and 6 meters as an alternative control service when meters are exchanged or removed before their useful life is covered under a metering exit service charge, classified in the final F&A.

<sup>359</sup> See CitiPower, Powercor and United Energy, *Submission on Victorian Preliminary Framework and Approach 2021-25* - 9 November 2018, p. 4

Received From	Key points of submission	AER response
Mr John Herbst	This submission focussed primarily on tariff reform.	While this submission is not in scope of the preliminary F&A, the tariff structure statement team will take this as a submission on the impending Victorian, SA and Qld TSS's.
Mr John Herbst	<p>In his submission to the TasNetworks draft decision<sup>360</sup>, John also made reference to the New Reg process which AusNet is currently trialling:</p> <p><b>New Reg will undermine transparency and consumer engagement<sup>361</sup></b></p> <p>Consumers awakening to the problems with Demand Tariffs will be especially frustrated to discover that Energy Consumers Australia (ECA) has been quietly complicit in this conspiracy. Energy Networks Australia will be joining ECA and the AER to form NEWREG, with the goal of settling more regulatory matters prior to drafting initial regulatory proposals. Making backroom agreements prior to presenting proposals to the public will not result in efficient outcomes for consumers, unless all parties can unwind agreements easily when the public points out mistakes and rule violations. The public's role is not simply to provide opinions, but also to enlighten regulators about issues that they may not have anticipated. Choosing to ignore customers reporting many diverse problems with Demand Tariffs for the reason "it has already been decided" is pure abuse of power.</p>	The New Reg process promotes transparency, accountability and innovation by providing customers with a mechanism to help the business develop its plans through the creation of a Customer Forum, rather than simply respond to those developed solely by the business. Transparency is supported by the requirement on both the regulated business and the Forum to evidence their negotiations with customer research and engagement. Additionally, once the proposal has been submitted the AER will follow its standard assessment and consultation process. The AusNet trial of this business has already yielded changes to the business' operations in addition to refining the regulatory proposal. <sup>362</sup>

<sup>360</sup> See: <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24/draft-decision>

<sup>361</sup> Mr John Herbst, *Submission on the AER's Draft Decision on TasNetworks 2019-2024 Regulatory Proposal*, 10 January 2019.

<sup>362</sup> More information can be found on our webpage: <https://www.aer.gov.au/networks-pipelines/new-reg>

