

Final Framework and approach for the Victorian Electricity Distributors

Regulatory control period commencing 1 January 2016

24 October 2014

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1. Shortened form

| Shortened form | Extended Form |
| --- | --- |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| capex | capital expenditure |
| CCP | Consumer Challenge Panel |
| CESS | capital expenditure sharing scheme |
| COAG Energy Council | Council of Australian Governments Energy Council (formerly Standing Council on Energy and Resources or SCER) |
| CPI | consumer price index |
| CPI-X | consumer price index minus X |
| current regulatory control period | 1 January 2011 to 31 December 2015 |
| DMIA | demand management innovation allowance |
| DMIS | demand management incentive scheme |
| DSDBI | Department of State Development, Business and Innovation (Victoria) |
| Distributor, DNSP | distribution network service provider |
| DUOS | distribution use of system |
| EBSS | efficiency benefit sharing scheme |
| expenditure assessment guideline | expenditure forecast assessment guideline for electricity distribution |
| F&A | Framework and Approach |
| kWh | kilowatt hours |
| MWh | Megawatt hours |
| NECF | National Energy Customer Framework |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER or the rules | National Electricity Rules |
| next regulatory control period | 1 January 2016 to 31 December 2020 |
| opex | operating expenditure |
| RAB | regulatory asset base |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |
| Smart meter | A type 4 metering installation in respect of which annual electricity consumption is up to 160 MWh and which has been installed to replace a type 5 or type 6 meter in accordance with clause 9.9C of the NER. |
| STPIS | service target performance incentive scheme |
| Vic | Victoria |
| WAPC | weighted average price cap |

1. **About the framework and approach**
2. The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution services in Australia's national electricity market (NEM).[[1]](#footnote-1) We are an independent statutory authority, funded by the Australian Government. Our powers and functions are set out in the National Electricity Law (NEL) and the National Electricity Rules (the rules or NER).
3. The framework and approach (F&A) is the first step in a process to determine efficient prices for electricity distribution services. This paper sets out our proposed approach on which services we will regulate and how we propose to apply relevant incentive schemes. It also assists network service providers prepare regulatory proposals.
4. AusNet Services (formerly SP AusNet), CitiPower, Jemena, Powercor and United Energy (the five Victorian electricity distributors) are licensed, regulated operators of Victorian (Vic) monopoly electricity distribution networks. The networks comprise the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. These electricity distribution network service providers (distributors) design, construct, operate and maintain distribution networks for Victorian electricity consumers.

We regulate a variety of services provided by the five Victorian electricity distributors. Where there is considerable scope to take advantage of market power, our regulation is more prescriptive. Less prescriptive regulation is required where prospect of competition exists. In some situations we may remove regulation altogether.

1. In June 2014, we made a decision to review the current Victorian F&A for the next regulatory control period.[[2]](#footnote-2) This decision arose following consultation with stakeholders.[[3]](#footnote-3) Our main reason for this decision was because of significant changes to the rules to introduce new incentive schemes and revised regulatory requirements, making portions of the current F&A irrelevant or inaccurate.
2. The current five year Victorian distribution regulatory control period concludes on 31 December 2015. This paper sets out our decisions for the next regulatory control period from 1 January 2016 to 31 December 2020 on the control mechanisms (how we determine prices for regulated services) to apply.

It also sets out our proposed approach for the next regulatory control period on:

* distribution service classification (which services are to be regulated)
* the formulae that give effect to the control mechanisms
* service target performance incentive scheme
* efficiency benefit sharing scheme
* capital expenditure sharing scheme
* demand management incentive scheme
* small-scale incentive scheme
* application of the expenditure forecast assessment guidelines
* whether depreciation will be based on forecast or actual capital expenditure
* jurisdictional and legacy issues.

1. Before reaching our proposed approach, we published a preliminary positions F&A on 18 June 2014, seeking submissions from interested parties. Submissions closed on 21 July 2014, with 9 responses received. We also consulted our Consumer Challenge Panel (CCP).[[4]](#footnote-4) Submissions and CCP views have been considered in reaching our decisions and proposed approaches set out in this F&A. A summary of submissions and our response is included at appendix A.
2. We will use the pre-lodgement process which follows the F&A process to commence discussions with the five Victorian electricity distributors about the treatment of confidential information as set out in our confidentiality guideline.[[5]](#footnote-5) We encourage the five Victorian electricity distributors to also consult consumers, as part of their consumer engagement, to gain a better understanding of the type of information consumers are interested in accessing.[[6]](#footnote-6)
3. Table 1 summarises the Victorian electricity distribution determination process.

Table 1: Victorian electricity distribution determination process

|  |  |
| --- | --- |
| Step | Date |
| AER published preliminary positions F&A for Victorian electricity distributors | 12 June 2014 |
| AER publishes final F&A for Victorian electricity distributors | 29 October 2014 |
| Victorian electricity distributors submit regulatory proposals to AER | 30 April 2015 |
| Submissions on regulatory proposal close | 31 July 2015\*\* |
| AER to publish preliminary distribution determination (prices set here take effect from 1 January 2016) | 30 October 2015\* |
| AER hold public forum on preliminary distribution determination | November 2015\*\* |
| Victorian electricity distributors to submit revised regulatory proposal to AER | 30 January 2016\*\* |
| Submissions on revised regulatory proposal and preliminary determination close | 9 March 2016\*\* |
| AER to publish substitute distribution determination for regulatory control period | 30 April 2016 |

\* The rules do not provide specific timeframes in relation to publishing draft decisions. Accordingly, this date is indicative only.

\*\* The dates provided for submissions and the public forum are indicative only. They are based on the AER receiving compliant proposals. These dates may alter if we receive non-compliant proposals.

Where a date falls on a weekend the actual date may be the next business day, as provided for in the NEL and the NER.

Source: NER, chapter 6, Part E.

1. Part A: Overview
2. The F&A provides an opportunity for interested parties, including consumers, to have a say in which services we should regulate and how much control we have over determining the prices for network services. The F&A also sets out information around incentive schemes that will apply to the five Victorian electricity distributors to encourage efficient investment and performance. This overview sets out our decision or proposed approach to:

* classification of distribution services (which services we will regulate)
* control mechanisms (how prices for regulated services are set) and the formulae that give effect to the control mechanisms
* treatment of dual function assets
* the application of a range of incentive schemes that encourage service quality, improvements in network reliability or efficient capital and operating expenditure and demand side response.
* the application of a range of expenditure forecasting expenditure tools used to test the five Victorian electricity distributors' regulatory proposals
* how we will calculate depreciation of the distributors' regulatory asset base going forward.

Classification of distribution services

1. Classification is important to electricity customers because it determines the need for and scope of regulation applied to distribution services central to electricity supply. Distribution services include, for example, the provision and maintenance of poles and wires and connection or disconnection to electricity. When we classify distribution services we determine the nature of the economic regulation we will apply to those services.
2. The rules establish a limited range of service classifications, to which varying levels of economic regulation apply. When we classify services we therefore determine whether we directly control prices, become involved only to arbitrate disputes, or do not regulate at all. The classification that we apply to a distribution service also determines whether the five Victorian electricity distributors recover service costs by averaging them across all customers or only charging those customers benefiting directly from specific services.
3. Table 2 below provides an overview of the different classes of distribution services for the purposes of economic regulation under the rules.
4. The classification of most distribution services will not change for the 2016–20 regulatory control period. The majority of services provided by distributors relate to building and maintaining the network and these will remain standard control services. we propose public lighting remain an alternative control service. We propose changing the classification of some metering services and a number of ancillary network services that distributors provide to individual customers. Our proposed approach is to classify a type 5 and 6 and smart meter - regulated service (i.e. a service not subject to competition) as alternative control. We classify a new type 5 and 6 and smart meter - unregulated service (i.e. which is to if this metering is subject to competition during the next regulatory control period) will be unclassified. This will facilitate more choice for customers. We also propose classifying ancillary network services as alternative control services to create a greater focus on 'user pays' for these services.
5. Table 2: Classifications of distribution services

|  |  |  |  |
| --- | --- | --- | --- |
| Classification | | Description | Regulatory treatment |
| Direct control service | Standard control service | Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. | We regulate these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services.  The costs associated with these services are shared by all customers via their regular electricity bill. |
| Alternative control service | Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor. | We set service specific prices to enable the distributor to recover the full cost of each service from customers using that service. |
| Negotiated service | | Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services. | Distributors and customers are able to negotiate prices according to a framework established by the rules. We are available to arbitrate if necessary. |
| Unclassified service | | Services that are not distribution services[[7]](#footnote-7) or services that are contestable and therefore do not need to be regulated. | We have no role in regulating these services. |

Source: AER

**Direct control services**

1. The rules set out factors we must have regard to when determining levels of economic regulation for the range of electricity distribution services. Following consideration of those factors, we may determine that a prescriptive approach is required. We will classify such services as direct control services. That is, we will directly set prices distributors may charge, or set revenues distributors may recover from customers through their charges.[[8]](#footnote-8)

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business.[[9]](#footnote-9) These are central to a distributor's business and its broad customer base uses them. Network services are central to a distributor's monopoly power and are frequently subject to licence restrictions. Therefore, our proposed approach is to classify network services as direct control services. Other distribution services are also subject to limited, or no, competition. We therefore also propose to classify as direct control: some metering, connections, public lighting and ancillary network services. We must further determine whether we will classify a direct control service as a standard control or alternative control service.

**Standard control services**

We classify as standard control those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. Standard control services reflect the integrated nature of an electricity distribution system. The costs of providing standard control services are averaged across all customers of a distribution network and recovered through standard network charges. These standard control services form the core distribution component of an electricity bill.

We propose to classify network services, new customer connections requiring augmentation and customer initiated works (connection service) as standard control services. These services encompass construction, maintenance and repair of the network, as well as augmenting the network to facilitate connecting new customers.

**Alternative control s**e**rvices**

1. Alternative control services are customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by a single distributor. For alternative control services we set specific prices to enable the distributor to recover the full cost of each service from customers using that service. We will determine prices for individual alternative control services in a variety of ways, suitable to specific circumstances. For example, only a few customers purchase ancillary network services (like a request to relocate a power pole). It would be inefficient for all customers to fund provision of these services. Therefore our proposed approach is to classify ancillary network services as alternative control.
2. Our proposed approach is to classify type 5 and 6 and smart meter - regulated services as alternative control because these services are charged for separately and provision of these services is likely to become open to more competition in future. The increasing range of metering services customers may wish to use (for example, smart meters) also suggests we should unbundle these services from standard control. Solar PV and small generator pre-approval fees and type 7 metering will also be classified as alternative control.
3. We have adopted United Energy's proposal to split the public lighting service into two services. A regulated service applicable to services involving shared public lighting assets and a negotiated service (see below) which relates to dedicated public lighting assets. We also propose to retain the current alternative control classification for public lighting where it involves shared public lighting assets, because a defined group of customers purchase these services, for example, local councils.

**Negotiated distribution services**

1. Negotiated distribution services are those we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing power to negotiate provision of those services. Distributors and customers are able to negotiate services and prices according to a framework established by the rules. We are available to arbitrate if necessary.
2. Our position is to continue to classify distribution services to supply emerging public lighting technologies and greenfield sites as negotiated distribution services. Note that this classification applies where the service is to be supplied by a distributor. Under the Public Lighting Code the possibility exists of contestable provision by other suppliers.[[10]](#footnote-10) The AER supports the continued application of the Code. As noted above, we have accepted United Energy's proposal to classify as negotiated a new service which relates to dedicated public lighting assets.[[11]](#footnote-11) Within this service we have further agreed to separate the replacement element from the operation, maintenance and repair service. Both services will be classified as negotiated services. Alteration and relocation of DNSP public lighting assets also will continue to be classified as a negotiated service.
3. AusNet Services proposed that constructing a reserve feeder should be reclassified from alternative control to a negotiated service. A reserve feeder is a second connection from the distributor to a customer. We consider that customers have a range of technological options to secure their energy supply and thus, constructing a reserve feeder is an option that is subject to competition. We also reclassify constructing a reserve feeder as a negotiated service.

**Unclassified (unregulated)**

In the case of some distribution services, we may determine there is sufficient competition for no regulation at all. We will not classify these services. We refer to these as unclassified or unregulated distribution services.[[12]](#footnote-12)

1. Some Victorian metering services are fully contestable (see figure 1 below). This is expected to extend to further categories in the next regulatory control period. Our view is that consumers have sufficient capacity, within contestable markets, to negotiate efficient prices for these services effectively. Therefore, we will not classify these services. This means we will have no role in the pricing of these services over the next regulatory control period.
2. Our approach is also not to classify emergency recoverable works. We consider that emergency recoverable works are distinguishable from other network services. This is because the cost of these works may be recovered under common law. This will create the right incentives for distributors to recover the cost of emergency recoverable works from third parties that caused damage to the network.

We use the above service classifications throughout this F&A. Figure 1 sets out our proposed approach to classification of distribution services for the five Victorian electricity distributors.

Control mechanisms

1. Following on from service classifications, our determinations must impose pricing controls on direct control service prices and/or their revenues.[[13]](#footnote-13) The form of control must be as set out in this F&A. The formulae that give effect to the form of control must be as set out in this F&A unless we consider unforeseen circumstances justify us departing from it when we make our determinations.[[14]](#footnote-14)
2. The rules require us to decide the control mechanism forms[[15]](#footnote-15) and propose the formulae to give effect to the control mechanism. In deciding control mechanism forms, we must select one or more from those listed in the rules.[[16]](#footnote-16) These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

* standard control services— revenue cap

We consider that a revenue cap best meets the factors set out under clause 6.2.5(c) of the rules. We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and is consistent with a move towards more efficient prices. Furthermore, we consider that the potential detriments of a revenue cap – within period pricing instability and weak pricing incentives are able to be mitigated. Therefore our proposed approach is to implement a revenue cap for the five Victorian electricity distributors' standard control services.

1. Figure 1: AER proposed approach to classification of Victorian distribution services

Source: AER

* alternative control services— caps on the prices of individual services. We consider this approach will provide cost reflective price benefits.
* for alternative control services charged on a quoted basis, we will adopt a cost build up approach.

1. For standard control services, the rules mandate the basis of the control mechanism must be the prospective CPI–X form, or some incentive-based variant.[[17]](#footnote-17) For alternative control services, we will confirm a control mechanism basis through the distribution determination process.

Incentive schemes

1. The purpose of incentive schemes is to encourage distributors to manage their businesses in a safe, reliable manner that serves the long term interests of consumers. The schemes provide distributors with incentives to only incur efficient costs and to meet or exceed service quality targets. In some instances, distributors may incur a financial penalty if they fail to meet set targets. These schemes include the service target performance incentive scheme, efficiency benefit sharing scheme, capital expenditure sharing scheme and demand management incentive scheme. The overall objectives of the schemes are to:[[18]](#footnote-18)

* encourage appropriate levels of service quality
* maintain network reliability as appropriate
* incentivise distributors to consider economically efficient alternatives to building more network
* incentivise distributors to spend more efficiently on capital and operating expenditure (opex)
* reduce the risk of consumers paying for unnecessary capital expenditure (capex)
* share efficient improvements and losses between distributors and consumers.

1. We outline below our proposed approach on the application of each scheme to the five Victorian electricity distributors.

Service target performance incentive scheme

1. Our national service target performance incentive scheme (STPIS) provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to safeguard service quality for customers against incentives for the distributors to seek out cost efficiencies.
2. Our proposed approach is to continue to apply the national STPIS to the five Victorian electricity distributors in the next regulatory control period with nominally, ±5 per cent financial reward or penalty based on whether the five Victorian electricity distributors meet the STPIS targets.[[19]](#footnote-19) We will not apply the guaranteed service level (GSL) component as the five Victorian electricity distributors will continue to be subject to a jurisdictional GSL scheme.[[20]](#footnote-20)

Efficiency benefit sharing scheme

1. The efficiency benefit sharing scheme (EBSS) aims to provide a continuous incentive for distributors to pursue efficiency improvements in operating expenditure (opex), and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices.
2. As part of our Better Regulation program we consulted on and published version 2 of the EBSS. Our proposed approach is to apply the new EBSS to the five Victorian electricity distributors in the next regulatory control period.

Capital expenditure sharing scheme

1. The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capital expenditure (capex) becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.
2. As part of our Better Regulation program we consulted on and published version 1 of the capital expenditure incentive guideline for electricity network service providers (capex incentive guideline) which sets out the CESS. Our proposed approach is to apply the CESS to the five Victorian electricity distributors for the next regulatory control period.

Demand management incentive scheme

1. Distributors have historically planned their network investment to provide sufficient capacity to provide for peak usage periods. As peak demand periods are typically brief and infrequent, network infrastructure often operates with significant redundant capacity. This underutilisation means that further investment in network capacity may not always be the most efficient means of catering for increasing peak demand. Demand management by distributors to lower or shift the demand for standard control services is incentivised through our demand management incentive scheme (DMIS).
2. Our proposed approach is to continue to apply the DMIS to the five Victorian electricity distributors for the next regulatory control period. As we intend the five Victorian electricity distributors' standard control services to operate under a revenue cap, we only apply Part A of the DMIS. That is, a demand management innovation allowance (DMIA). The DMIS adds an innovation allowance to each distributor's revenue each year of the regulatory control period. In calculating the allowance, we must have regard to a range of factors around benefits to consumers and how the DMIS balances against other incentive schemes. For the next regulatory control period, the allowance will be determined as part of our revenue determination.

Small-scale incentive scheme

1. The rules state that we may develop a small-scale incentive scheme.[[21]](#footnote-21) We have not developed this scheme. Therefore, our proposed approach is not to apply this scheme to the five Victorian electricity distributors in the next regulatory control period. AusNet proposed that the AER develop an incentive to encourage improvements in the accuracy of demand and energy forecasting by service providers.[[22]](#footnote-22) There is merit in this proposition but the development of any incentive scheme must be subject to consultation with all affected stakeholders across the NEM rather than be jurisdiction-specific. It is unlikely this process could be undertaken in time for the preparation of regulatory proposals by the Victorian businesses due in April 2015.

Application of the expenditure forecast assessment guideline

1. In December 2013 we published our expenditure forecast assessment guideline for electricity distribution (expenditure assessment guideline). The expenditure assessment guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. Our proposed approach is to apply the guideline, including the information requirements to the five Victorian electricity distributors in the next regulatory control period.
2. The expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the five Victorian electricity distributors' regulatory proposals. We intend to apply all the assessment tools set out in the guideline.

Depreciation

1. Changes to the rules require us to state our approach to calculating depreciation when we roll forward the five Victorian electricity distributors' regulatory asset base (RAB) for the 2021–2025 regulatory control period. Our proposed approach is to use forecast depreciation to establish the RAB as at 1 January 2021.
2. The depreciation we use to roll forward the RAB can be based on actual capex incurred during the regulatory control period. Alternatively, we may use the capex allowance forecast as at the start of the regulatory control period.
3. Our proposed approach to use forecast depreciation, in combination with our proposed application of the CESS will maintain incentives for distributors to pursue capex efficiencies. These improved efficiencies benefit consumers through lower regulated prices.

Jurisdictional and legacy issues

1. For issues we can address in the F&A, we have set out our proposed approach and reasons. We will address any remaining issues as part of our normal consultation with the distributors. This commences before they must submit regulatory proposals for our consideration and continues through the determination process.

F-factor scheme

1. The Victorian Government has in place the 'f-factor' scheme which provides incentives for Victorian DNSPs to reduce the risk the risk of loss or damage caused by fire starts.[[23]](#footnote-23) The scheme is implemented by an Order issued under the National Electricity (Victoria) Act 2005. This Order confers functions and powers on the AER to regulate the f-factor scheme.

Our preliminary position was that we would maintain the incentive rate of $25,000 per fire for the forthcoming regulatory control period and continue to monitor the effect of the initial incentive mechanism. DSDBI has advised that they will review the scheme in 2014-15.[[24]](#footnote-24) We will apply this scheme in its amended form, as advised by DSDBI.

Dual function assets

Dual function assets are high voltage transmission assets forming part of the distribution network. Where a network service provider owns, controls or operates dual function assets, we are required to decide whether to treat the assets as transmission or distribution assets.[[25]](#footnote-25)

1. No Victorian distributor currently owns, controls or operates 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.[[26]](#footnote-26) Therefore, our decision is that we are not required to, and will not make any determination under the rules regarding dual-function assets.[[27]](#footnote-27)
2. Part B: Attachments

# AER-final-orangeClassification of distribution services

1. This attachment sets out our proposed approach to the classification of distribution services provided by the five Victorian electricity distributors for the next regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification therefore determines whether we:

* directly control prices[[28]](#footnote-28)
* allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
* do not regulate at all.

If we control prices directly, classification further determines whether distributors recover service costs from all customers or only those benefiting directly from specific services.[[29]](#footnote-29)

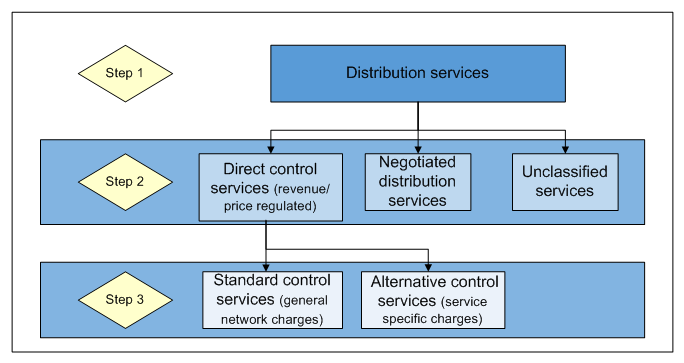
1. Classification is important to customers as it determines which network services are included in basic electricity charges, which are sold as additional services and which we will not regulate. Our decisions reflect our assessment of a number of factors, including competition, or the potential for competition, of service supply. When necessary, we classify services with a more prescriptive form of regulation. If possible, we classify services with less prescriptive forms of regulation or do not regulate at all. If specific customers use a service we may consider classifying it to establish a user pays approach to pricing.

Service classifications must be as set out in this F&A unless we consider unforeseen circumstances justify us departing from the classification as set out in this F&A.[[30]](#footnote-30)

1. The rules set out a three step classification process we must follow. We must consider a number of specified factors at each step. Figure 2 outlines the classification process under the rules.
2. As illustrated by figure 2 below:

* We must first satisfy ourselves that a service is a 'distribution service' (step 1). The rules define a distribution service, as 'a service provided by means of, or in connection with, a distribution system.'[[31]](#footnote-31) A distribution system is defined as 'a distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.[[32]](#footnote-32)
* We then consider whether economic regulation of the service is necessary (step 2). When we do not think economic regulation is warranted we will not classify the service. If economic regulation is necessary, we consider whether to classify the service as either a direct control or negotiated distribution service.
* When we think we should classify a service as direct control, we further classify it as either a standard control or alternative control service (step 3).

Figure 2: Distribution service classification process

1. 

Source: AER.

1. Our classification decisions determine how distributors will recover the cost of providing services. Distributors recover standard control service costs by averaging them across all customers using the shared network. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. The whole cost of the service is paid by those customers who benefit from the service.
2. For services we classify as negotiated, distributors and customers will negotiate service provision and price under a framework established by the rules. Our role in regulating negotiated services is to arbitrate disputes where distributors and prospective customers cannot agree terms. Two instruments support the negotiation process:

* Negotiating distribution service criteria[[33]](#footnote-33)—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[[34]](#footnote-34)—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.

1. For services we do not classify, we will have no role at all.

## AER's proposed approach

1. Before considering how to classify services, we consider how to group them. This allows a more straightforward approach to classification, as our classification decisions for a group of services relates to each service within the group. Our proposed approach is to group distribution services provided by the five Victorian electricity distributors as:

* network services
* connection services
* metering services
* ancillary network services
* public lighting services.

1. We consider each service falling within the above service groups is a distribution service.[[35]](#footnote-35) They are services provided by means of, or in connection with, a distribution system.[[36]](#footnote-36)
2. We propose to classify the distribution services provided by the five Victorian distributors consistently. Distribution services provided by all distributors will have the same classification. Figure 3 summarises our proposed classification of the five Victorian electricity distributors' distribution services. This section summarises our proposed approach to the classification of each service group.
3. Network services are at the core of what an electricity distributor does, including constructing and maintaining those parts of the electricity network that everyone uses—that is, the shared distribution network. provide network services in their respective geographic areas under exclusive distribution authorities or franchises, issued by the Victorian Government. This restriction on competition exists because it would be inefficient to have more than one network in the same geographic location. Competition in the provision of network services would not be in the interests of customers because electricity prices would have to be higher, reflecting the higher costs of having to build and maintain a duplicate distribution network.
4. A distributor's broad customer base uses network services through a shared network, provided by distributors under monopolistic conditions. Therefore, we classify network services as standard control services so distributors recover the cost of providing network services from across their broad customer base. The lack of effective competition in the provision of network services gives further weight to classifying network services as standard control services.
5. Connection services relate to connecting new customers to the shared network. In Victoria, we classify new connections requiring augmentation as standard control services and routine connections as alternative control services. We will retain this approach. In our preliminary positions paper we stated that we may need to re-consider these classifications if the Victorian Government were to adopt the National Energy Customer Framework (NECF) or to take steps to adopt the application of Chapter 5A of the National Electricity Rules in the next regulatory control period.[[37]](#footnote-37) We are satisfied that no re-classification will be necessary because connection services would be regulated on an equivalent basis under the AER's connection guideline.

Figure 3: AER's proposed classification of Victorian distribution services

Source: AER

1. Public lighting is currently an alternative control service in Victoria. Our approach is to retain this classification because public lighting services are provided to specific customers—usually local government councils. However, we encourage greater consultation and collaboration between the distributors and councils to improve the processes that apply to this service.
2. A negotiated distribution service is a classification that reflects a light handed approach to regulation. Service providers and prospective users negotiate services and prices according to a framework set out in the rules. We are available to arbitrate if necessary. This classification relies on both parties possessing sufficient market power to effectively negotiate. We propose to classify new technology and greenfield public lighting as negotiated services. In our preliminary positions F&A we noted the possibility of classifying all public lighting services as negotiated services.[[38]](#footnote-38) However, although we consider the potential benefit associated with competitive provision of all public lighting is a desirable long-term outcome, having taken submissions into account, access to public lighting attached to shared use poles remains restricted by safety considerations under current regulations.[[39]](#footnote-39) AusNet Services proposed that the construction of a reserve feeder be reclassified as a negotiated service on the basis that it is an alternative to other options available to the customer, such as on-site generation. We considered whether this activity should be unclassified but, as there is a limited competition for this service we have accepted AusNet Services' proposal that it should be a negotiated service. We also agree that as the circumstances of each customer will differ, the service for maintenance of a reserve feeder should be a quoted service, not fee based.
3. Advanced Metering Infrastructure (AMI) metering applies to Victorian residential and small business customers using up to 160 MWhrs of electricity per annum. Our proposed approach to the transition from regulation of AMI services under the current Victorian arrangements to regulation under the NER attracted significant comment.[[40]](#footnote-40) We have amended our service classification approach in response to those comments. Victoria has in place a derogation from the NER which expires on or before 31 December 2016.[[41]](#footnote-41) This derogation appoints the five Victorian electricity distributors as the monopoly supplier of type 5 and type 6 metering. Until the derogation expires, the costs of these services are regulated by the AER under an Order-in-Council (CROIC) issued by the Victorian Government.[[42]](#footnote-42) This will continue to apply until the expiry of the derogation.
4. As competition may be introduced during the next regulatory control period (following the expiry of the derogation) it is necessary for two AMI related services to be classified - one a regulated service which is supplied as a monopoly service by the distributor and a second service which is supplied in a competitive market. Metering services provided to residential and small business customers by the distributor under the AMI CROIC and which continue to be supplied until replaced by a competitively supplied meter will be classified as alternative control. The service will be subject to a revenue cap, as we consider this most accurately reflects the approach to regulation under the AMI CROIC.[[43]](#footnote-43) The AEMC, in its consultations on introducing metering competition to Victoria, has stated that:

The NER mandates that smart metering in Victoria be classified as an alternative control service in the 2016-2020 regulatory control period…[[44]](#footnote-44)

1. Exit fees will apply to meters subject to a revenue cap. These fees will be determined as part of the revenue determination process. To facilitate the transition to a fully competitive market, metering services supplied on a competitive basis by third parties to new residential or small business customers up to 160 MWhrs will be unclassified.[[45]](#footnote-45)
2. We also propose to not classify 'emergency recoverable works', though not for reasons relating to their contestability. Emergency recoverable works relate to the repair of the network after an identifiable third party has caused damage. This third party is liable at common law for the costs of repair. The cost of these works will be covered by common law, rather than by the NER. We consider that by not classifying this service we will establish the right incentives for distributors to recover costs from responsible parties.

## AER's assessment approach

1. The rules allow us to group distribution services when classifying them. This means we may classify a class of services rather than specific services. 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.
2. When deciding whether to classify services as either direct control or negotiated services, or to not classify them, the rules require us to have regard to the 'form of regulation factors' set out in the NEL.[[46]](#footnote-46) We have reproduced these at appendix C. The form of regulation factors broadly include, amongst other things, the presence and extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The rules also require us to consider the previous form of regulation applied to services, the desirability of consistency with the previous approach and any other relevant factor.[[47]](#footnote-47)
3. For services we intend to classify as direct control services, the rules require us to have regard to a further range of factors.[[48]](#footnote-48) Broadly, these include the potential to develop competition in provision of a service and how our classification may influence that potential. Also, whether the costs of providing the service are attributable to a specific person. And, the possible effect of the classification on administrative costs.
4. The rules also specify that for a service regulated previously, unless a different classification is clearly more appropriate, we must:

* not depart from a previous classification (if the services have been previously classified), and
* if there has been no previous classification—the classification should be consistent with the previously applicable regulatory approach.[[49]](#footnote-49)

## Reasons for AER's proposed approach

1. This section sets out our proposed approach for classification and our reasons. In turn, this section deals with:

* network services
* connection services
* metering services
* ancillary network services
* public lighting.

Before addressing each of the service groups listed above, we first address how we have developed the service groupings to which we will apply our classification approaches.

### Service group descriptions

1. We consider our service group descriptions should allow stakeholders to understand our proposed classifications while avoiding unnecessary detail. The table of service classifications attached to our preliminary positions F&A[[50]](#footnote-50) provided detail where required for clarity, but avoided being an exhaustive list of activities that are actually components of services. Were we to set out each activity undertaken as a component of each distribution service we classify, the documentation would become unwieldy. Our approach to defining services in the preliminary positions F&A classifications table was supported by all of the Victorian distributors with some notable exceptions. These are discussed in the following sections, as they arise.

We have produced a single classifications table as appendix B to this F&A paper.

### Network services

Distributors provide network services over a shared distribution network to all customers connected to it.[[51]](#footnote-51) Customers use or rely on network services on a daily basis. Examples include the construction and maintenance of the shared network.

1. We propose to classify network services as direct control services and further, as standard control services. We also propose not to classify emergency recoverable works, even though they are similar to network services.
2. The Electricity Industry Act 1994 (Victoria) prevents a person from distributing and supplying electricity unless they hold a Licence permitting them to do so.[[52]](#footnote-52) Additionally, customers cannot source network services in their district from external providers.[[53]](#footnote-53) AusNet Services, CitiPower, Jemena, Powercor and United Energy each hold the only electricity distribution licences for their respective distribution areas.[[54]](#footnote-54) These arrangements together provide a regulatory barrier, preventing third parties from providing network services.[[55]](#footnote-55) Therefore, we consider that there is no market for network services in which third parties could compete. The five Victorian electricity distributors possess significant market power due to the regulatory arrangements in place.[[56]](#footnote-56) Therefore, we intend to classify network services as direct control services.
3. We must further classify direct control services as either standard or alternative control services.[[57]](#footnote-57) We propose to retain the current standard control classification for network services. There is little, if any, potential to develop competition in the market for network services.[[58]](#footnote-58) The absence of competition is due to the five Victorian electricity distributors holding the only licences to provide network services in each distribution area. There would be no material effect on administrative costs for us, the distributors, users or potential users because a standard control classification is consistent with the current regulatory approach. [[59]](#footnote-59) Also, we currently classify network services in all NEM jurisdictions as standard control services.[[60]](#footnote-60) And finally, distributors provide network services through a shared network, so cannot directly attribute the costs of these services to individual customers.[[61]](#footnote-61) All five Victorian electricity distributors supported our proposed approach.[[62]](#footnote-62) Other submissions did not comment on this issue.

Emergency recoverable works

'Emergency works' relate to repairing the distribution network after damage to restore or maintain electricity supply. Repairing damage caused by a storm is an example of such works. 'Emergency recoverable works' relate to the distributors' emergency work to repair damage following a person's act or omission, for which that person is liable. For example, repairs to a power pole following a motor vehicle accident. We currently classify Victorian distribution emergency recoverable works as alternative control services.

1. Distributors carry out emergency recoverable works as part of the normal maintenance and repair to the network to ensure the safe and reliable supply of electricity. Only a distributor may perform these types of repairs on its assets.
2. Given that these services are provided in connection with a distribution system, we consider emergency recoverable works are a distribution service. However, in terms of classification, we consider that emergency recoverable works are distinguishable from other network services. This is because the cost of these works may be recovered under common law. That is, the distributors can seek payment of their costs to fix the network from the parties responsible for causing the damage, through the courts if necessary. The rules set out a number of matters we must have regard to in classifying distribution services, including 'any other relevant factor'.[[63]](#footnote-63) The manner of cost recovery is a relevant factor. This view is reinforced when it is considered in light of the National Electricity Objective (NEO). Broadly, the NEO requires us 'to promote the long term interests of consumers of electricity' with respect to the national electricity system (see footnote below for the full text of the NEO).[[64]](#footnote-64) It is in the interests of electricity consumers that the costs of network repairs be recovered from the party or parties responsible for the damage, rather than users of the network. For this reason, we propose not to classify emergency recoverable works.[[65]](#footnote-65)
3. By not classifying emergency recoverable works, distributors are not able to recover costs for these services from consumers. To be compensated for damage to the network caused by an identifiable party, distributors must seek to recover costs from that party. We consider this will establish the right incentives for each distributor to pursue costs from parties responsible for damage to distribution network assets. Our proposed classification is also consistent with our approach to the classification of emergency recoverable works in NSW.[[66]](#footnote-66)
4. In response to our preliminary positions F&A, Jemena, CitiPower and Powercor agreed with the our decision to 'un-classify' recoverable works.[[67]](#footnote-67) However, AusNet Services submitted that emergency recoverable works should remain classified as a direct control service.[[68]](#footnote-68) They further proposed that it remain a network service and so be classified as standard control.[[69]](#footnote-69) In support of their preferred approach, AusNet submitted that this was a 'non-existent problem' and that the cost would have to be met through insurance.[[70]](#footnote-70)
5. We are not persuaded by the arguments of AusNet Services that we should change our proposed classification of emergency recoverable works. We have discussed above the relevance of cost recovery to our classification decision. A more relevant classification decision is the approach we have taken in NSW, where we not classified this service for the same reasons as our proposed approach to Victoria.[[71]](#footnote-71) The NSW distributors supported our approach to not classify emergency recoverable works, as does CitiPower and Powercor.[[72]](#footnote-72) We consider that in circumstances where the party responsible for damaging the network is not identifiable, related costs are not recoverable. Therefore, works to repair that damage would not be considered emergency recoverable works. Rather, they would be emergency works.
6. Distributors already incur administrative costs in recovering costs from parties responsible for damaging the network. We consider any further administrative costs associated with changing classification will be outweighed by the benefits to customers of not having to bear the costs of network repair where the distributor can recover them directly from the responsible parties.[[73]](#footnote-73) That AusNet Services would include insurance cover for any losses in its opex is a normal business practice. The magnitude of this inclusion is unlikely to be material.
7. We consider that the cost of emergency recoverable works being recovered from parties responsible for damaging the network is clearly more appropriate than the present classification, under which customers pay.[[74]](#footnote-74) Therefore, we consider not classifying emergency recoverable works is clearly more appropriate than the present classification approach.[[75]](#footnote-75)

### Connection services

1. Chapter 10 of the rules defines connection services.[[76]](#footnote-76) Put simply, 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
* get more electricity from the distribution network than is possible at the moment
* extend the network to reach a person’s premises.

1. We consider it possible to separate connection services into clearly identifiable components. Table 3 lists our proposed definitions of each connection type together with our proposed classification of each type.

Table 3: AER's proposed approach for Victorian connection services

|  |  |  |
| --- | --- | --- |
| 1. Service group | 1. Current classification | 1. AER proposed classification |
| 1. Routine connections (not requiring augmentation) | 1. Alternative control | 1. Alternative control |
| 1. New connections requiring augmentation. | 1. Standard control | 1. Standard control |
| 1. Temporary connections and disconnections | 1. Alternative control | 1. Alternative control |
| 1. Inspection of PV installation site | 1. Alternative control | 1. Alternative control |
| 1. Energisation and de-energisation | 1. Alternative control | 1. Alternative control |
| 1. Supply enhancement at customer request | 1. Alternative control | 1. Unclassified |
| Operate and maintain connection assets (captured as network services) | 1. Standard control | 1. Standard control |
| Customer initiated undergrounding and/or rearrangement of distribution assets serving that customer\* | 1. Alternative control | 1. Standard control |

\* See discussion under 'New connections requiring augmentation'. This service classification is subject to a customer contribution payment to be calculated in accordance with the ESCV Guideline 14 or the AER's connection guideline.

Source: AER

We consider each connection type separately below.[[77]](#footnote-77)

Routine connections

We currently classify routine connections (that is, connections that do not require augmentation of the shared network) as direct control and alternative control services. Our preliminary position was to retain the alternative control classification of these services.

1. Victorian licensed electricity distributors are subject to the Victorian Electricity Distribution Licence conditions. The Distribution Licence imposes conditions on distributors to process electricity connection applications in accordance with guidelines issued by the Essential Services Commission of Victoria. These are Victorian Electricity Industry Guidelines 14 and 15.[[78]](#footnote-78) New connections requiring augmentation are subject to limited contestability under the Victorian Electricity Industry Guideline 14. This means a process exists under Guideline 14 for the distributor to arrange competitive tenders by an authorised contractor to perform connection works that require components of the distributors system to be upgraded. Routine connections that do not require augmentation of the shared network are not made contestable under Guideline 14.

The Victorian distributors can identify costs associated with the provision of these services and can attribute those costs to individual customers who receive those services. Therefore our preliminary position is to retain the alternative control classification of these services.

Jemena did not agree with this classification. Jemena argue that if standard control services are subject to a revenue cap then Jemena would be under an incentive to discourage or delay new connections.[[79]](#footnote-79) This arises because of forecasting errors by the AER in setting the initial capex and opex allowances or because of cost overruns in implementing the service requests. We do not accept this argument is sufficient reason to change this classification. The obligation to connect a customer arises from holding a distribution licence. The process for responding to a connection enquiry is also governed by the Electricity Distribution Code (Vic).[[80]](#footnote-80) The responsibility for preparing a credible forecast of connections lies with the distributor, not the AER. It is only if the distributor fails to justify that forecast that the AER substitutes a different forecast. Consequently, although it is true that the effects of forecasting error and cost overrun do incentivise the business to manage this expenditure, this incentive is offset by having a positive obligation under the Electricity Distribution Code to implement connections in a timely fashion. As the regulation framework is incentive based, it is appropriate for the DNSP to bear these risks.

New connections requiring augmentation

1. We currently classify new connections requiring augmentation as direct control and standard control services. We propose to continue classifying new connections requiring augmentation as direct control and standard control services on the basis that they will continue to be subject to Guideline 14 or, if Victoria adopts chapter 5A of the NER, the AER's connection guideline.
2. New connections requiring augmentation are subject to limited contestability under Guideline 14. Guideline 14 also limits the amount of the customer's capital contribution that a Victorian distributor can charge for a connection requiring augmentation. If such service is classified as alternative control or negotiated service, new customers will be paying more for the connection service because the expected incremental network revenue will not be taken into consideration to off-set the incremental cost for connection. This was the rationale behind the current service classification.
3. All five Victorian distributors submitted that customer initiated works to reconfigure distribution assets — including the undergrounding of power lines –— were also captured under Guideline 14 but were currently classified as alternative control.[[81]](#footnote-81) They argue that the same considerations apply to these other works as apply to routine connections requiring augmentation and therefore the correct classification would be standard control. We agree, but only for connection assets serving that customer. This is on the basis that, as a connection service, the size of the customer's capital contribution will be calculated as provided for in Guideline 14 or, if Chapter 5A applies, the AER's connection guideline. We have amended the service classification for these works accordingly. All other works undergrounding and supply rearrangement works remain subject to the 'ancillary services' classification group.

Supply abolishment

1. AusNet services proposed that the routine supply abolishment <100 amps service be reclassified as a standard control service.[[82]](#footnote-82) The service is currently classified as alternative control (fee based). The reason AusNet Services advanced for doing this was to remove the incentive for customers to not report to the distributor that a disused service was creating a potential community safety hazard and an abolishment is required. We recognise that on leaving premises it will often be the case that the departing party has a strong incentive to avoid paying the full costs that various suppliers may levy. Although this service does apply to individual customers and thus, is suitable for the alternative control classification, as this situation may lead to a significant safety hazard where an electrical installation is involved, we accept AusNet Services proposal. We have reclassified supply abolishment (<100 amps) as standard control.

Transition to chapter 5A framework in the NER

1. In our preliminary positions paper we expressed a preference to maintain a common, nationally consistent approach to the matters we regulate. Notably, to apply the chapter 5A framework of the NER in Victoria. Adoption of chapter 5A is tied to introduction of the national electricity customer framework (NECF). In response, DSDBI have stated:[[83]](#footnote-83)

Adoption of the NECF in Victoria would require a package of jurisdictional legislative amendments which will take time to prepare and implement, and cannot be assumed to be in place before October 2015.

1. On this basis we will continue to operate on the basis that Guidelines 14 & 15 will apply. We note that the Victorian Government has released an energy statement, in which they state as Priority 1.3:

The Victorian government’s retail energy regulatory arrangements will transition to NECF by 31 December 2015.[[84]](#footnote-84)

1. If it can be established in time for our determination that Guidelines 14 (and 15) are to be removed and not replaced with new jurisdictional charging provisions, then our intention is to apply the AER's connection guideline to the Victorian distributors.

Operating and maintaining connection assets

1. We consider that once completed, a connection becomes part of the shared distribution network. That is, the Victorian distributors will operate and maintain connection assets as part of their routine maintenance of the shared network. As such, our position is to classify the operation and maintenance of connection assets as direct control and standard control services.

Inspection of PV installation site

This service covers the site inspection for distribution network users that have installed photovoltaic (PV) units, including testing of the inverter and related equipment. This service is currently classified as a direct control and alternative control service on the basis that:

* The Victorian distributors are the only parties that can provide this service for electrical safety reasons
* The nature and scope of the works can be known with reasonable certainty, the cost of providing the service can be estimated in advance with reasonable certainty, and a generic schedule of prices can be set before the service is requested
* The service, and therefore the cost, can be directly attributed to specific customers.

We consider these factors remain relevant. This service is not explicitly listed in the current classifications but has fallen under a broader category of connection services classified as direct control, alternative control services. We propose to retain the classification of PV inspection services as direct control and alternative control services. DSDBI submitted that they agreed with this classification.[[85]](#footnote-85) They went on to suggest that the charge for pre-approval work should be a fee based charge but that the DNSPs were best placed to comment on the variability of the scope of works for larger installations. AusNet Services proposed that charges for small solar PV installations up to 5kW be fee based and for larger systems a quoted service, whilst CitiPower and Powercor noted an intention to amend its business practices for small PV schemes to rely on sample auditing of compliance.[[86]](#footnote-86) For larger systems, although there is likely to be some variation in the scope of works, we are not persuaded that this variation would be sufficient to justify a quoted service. We consider that a fee based approach remains appropriate for these services.

Temporary connections and disconnections

1. Distributors provide temporary connection and/or disconnection services to specific customers on request. Examples include blood bank vans and school fetes. AusNet supported this classification.[[87]](#footnote-87) Because only the distributor may provide temporary connections, we classify these as direct control services.[[88]](#footnote-88) As they are provided to specific customers, we further classify temporary connections as alternative control services.[[89]](#footnote-89) This is consistent with the current classification.

Energisation and de-energisation

Energisation and de-energisation services are the connection or disconnection of electricity when a customer moves in or vacates premises or the service is disconnected for other reasons such as safety or non-payment of bills. These services are classified as direct control and alternative control services on the basis that:

* The Electricity Industry Act 2000 (Vic) obliges the Victorian distributors to provide these services upon request and prevents any other party from providing these services[[90]](#footnote-90)
* The economies of scale and scope available to the Victorian distributors, in particular in relation to network services, are likely to prevent these services being competitively provided by alternative service providers
* The nature and scope of the works can be known with reasonable certainty, the cost of providing the service can be estimated in advance with reasonable certainty, and a generic schedule of prices can be set before the service is requested
* The cost of providing these services can be directly attributed to specific customers.

1. In our Preliminary Positions paper we proposed to adopt the classification of energisation and de-energisation services as direct control and alternative control services.[[91]](#footnote-91) AusNet supported this classification.[[92]](#footnote-92) These services can now be provided on a remote basis using AMI and at a much lower cost. The AER currently determines these charges under to AMI CROIC, however, in the next regulatory control period this will be under the NER.

Supply enhancement at customer request

This service is currently classified as a direct control, alternative control service. However, the Victorian distributors submitted that the service has not been provided in the current regulatory control period, with the activities instead being provided as a routine connection or new connection requiring augmentation.[[93]](#footnote-93) Accordingly, we do not consider that this service requires classification in Victoria.

### Metering services

1. This section first explains the different metering types and different metering services. In doing so, we summarise the categories of metering services we propose to apply and our proposed classification of the different metering types. Second, we set out our reasons for our proposed approach to the classification of metering services.

Introduction to metering services

1. There are different types of metering installation types, measuring electricity usage in different ways. Table 4 below describes each metering installation type.

Table 4: Metering installation types

|  |  |
| --- | --- |
| Metering type | Description |
| Type 1 to 4 meters [[94]](#footnote-94) | These are generally used by large customers who consume greater than 160 megawatt hours (MWh) of electricity per annum. However, type 4 is also used by small customers, including residential and small business customers in Victoria as replacements for the older types 5 & 6 meters. Types 1 to 4 have the capability to record the time of use of energy and are read remotely. |
| Type 5 meters | Manually read interval meters with capability to record time of use of energy. |
| Type 6 meters | Manually read accumulation meters which simply record total electricity usage. Formerly the default meter type in Victoria for households and other small consumption users. |
| Type 7 meters | Type 7 meters are unmetered connections. Examples include streetlights or traffic lights. Usage of electricity by type 7 meter connections is estimated using formulae and standard data. |

Source: AER

1. All electricity customers have a meter that measures the amount of electricity they use.[[95]](#footnote-95) Metering installation types are defined in schedule 7.2 of the NER,[[96]](#footnote-96) However, not all customers have the same type of meter. Large customers use type 1 to 4 meters which provide a range of additional functions compared to type 5 and 6 meters. Type 1 to 4 meters are competitively available and we do not currently regulate them for Victorian customers—they are unclassified. Type 1 to 4 meters are competitively available for purchase from the five Victorian electricity distributors or from alternative providers. These are interval meters with a communications capability allowing distributors or a third party to read them remotely.
2. Because Victoria has had a roll-out of Advanced Metering Infrastructure (AMI), we must first introduce a new defined term — 'smart meter'.93 In plain language, a smart meter is an electronic meter that replaces an older technology meter. Its special advantage is that it can be read remotely and (in Victoria) has the capacity to be turned on or off remotely. Although smart meters are, technically speaking, a type 4 meter they were deemed by a Victorian Government derogation contained in clause 9.9C of the NER to be type 5-6.[[97]](#footnote-97) In the following sections we will discuss how the derogation has affected the classification decision we must make.
3. The five Victorian electricity distributors were the monopoly providers of type 5 (interval) and 6 (accumulation) meters.[[98]](#footnote-98) In the past, households and other small customers used these meter types. Type 6 meters simply record total electricity usage over a period of time. Type 5 meters can record electricity usage and time of use.[[99]](#footnote-99) The Victorian Government decided on a mandatory roll-out by the five Victorian electricity distributors of smart meters for all small business and residential customers using up to 160 MWhrs per annum of electricity. Smart meters have almost entirely replaced types 5 & 6 meters for residential and small business consumers in Victoria. Smart meters offer frequent information about usage and facilitate a range of other services as well as more flexible pricing.[[100]](#footnote-100) This allows customers to manage their electricity use better.
4. The five Victorian electricity distributors are the monopoly providers of type 7 metering services, which are unmetered connections (for example, public lighting connections).[[101]](#footnote-101) Such connections do not include a meter that measures electricity use. Rather, electricity use by these connections is estimated. Charges associated with type 7 metering services relate to the process of estimating electricity use.
5. Auxiliary metering services are a range of other metering related services provided to specific customers. These include customer-requested meter tests, additional meter reads or equipment alterations.
6. Type 5 and 6 metering services, including smart meters for smaller customers, are currently unclassified because they are not regulated under the NER. Rather, they are currently regulated under the AMI CROIC. This means the current classification of metering services (i.e. unclassified) applies to meter installation, provision, maintenance, reading and data management.
7. Table 5 summarises the current classification and our proposed approach to the classification of metering services.

Table 5: AER's current and proposed classification of metering services

|  |  |
| --- | --- |
| Current classification | AER’s proposed classification |
| Metering types 1 to 4 – unclassified | Metering types 1 to 4 (excluding smart meters) – unclassified |
| Metering types 5 and 6 and smart meters - regulated service – unclassified (subject to AMI CROIC) | Metering types 5 and 6 and smart meters - regulated service - alternative control – This includes installation (including on site connection of a meter at a customer’s premises, and on site connection of an upgraded meter at a customer's premises where the upgrade was initiated by the customer), provision, maintenance, reading and data services. Meter provision refers to the capital cost of purchasing the metering equipment to be installed. Meter maintenance covers works to inspect, test, maintain, repair and replace meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services involve the collection, processing, storage, delivery and management of metering data. |
| Metering types 5 and 6 and smart meters - unregulated service – unclassified (service not currently provided) | Metering types 5 and 6 and smart meters - unregulated service - unclassified – This includes installation (including on site connection of a meter at a customer’s premises, and on site connection of an upgraded meter at a customer's premises where the upgrade was initiated by the customer), provision, maintenance, reading and data services. Meter provision refers to the capital cost of purchasing the metering equipment to be installed. Meter maintenance covers works to inspect, test, maintain, repair and replace meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services involve the collection, processing, storage, delivery and management of metering data. |
| Meter type 7 – Alternative control | Meter type 7 – Alternative control |
| Auxiliary metering services – alternative control | Auxiliary metering services – Alternative control |

Source: AER

Type 1 to 4 metering services (excluding smart meters)

1. Type 1 to 4 metering services are contestable in Victoria and competitively available.[[102]](#footnote-102) For this reason, our decision is not to classify these services, save for the special case of type 4 where it involves smart meters.[[103]](#footnote-103) Consequently, we will not regulate types 1-3 or type 4 meters which were not installed under the Victorian Government's Advanced Metering Infrastructure (AMI) Cost Recovery Order-in-Council (CROIC).[[104]](#footnote-104) This classification of type 1 to 4 metering services is consistent with the current regulatory approach in Victoria and in other jurisdictions.[[105]](#footnote-105)
2. Note that type 4 metering installations are remotely read interval meters and apply to any situation with an energy consumption less than 750 MWhrs per annum. In the next section we will discuss smart meters, which are remotely read interval meters installed to replace type 5 and 6 metering installations for residential and small business customers consuming up to 160 MWhrs per annum. Thus, as previously discussed, smart meters would normally fall under the type 4 metering definition and not the type 5 definition, which applies to manually read interval meters.

Type 5 and 6 and smart meters — regulated service

1. The five Victorian electricity distributors are the monopoly providers of type 5 and 6 meters.[[106]](#footnote-106) Type 5 and 6 meters have been almost entirely replaced by smart meters for residential and small business consumers. Note that this classification discussion relates only to the provision of type 5, 6 or smart meters as a monopoly service. For type 5, 6 or smart meters supplied subject to competition (discussed later) we define a separate unregulated service, which is unclassified.
2. While the current metering definitions remain in place in schedule 7.2 of the NER a distinction must be made between smart meters which were installed in accordance with the AMI CROIC and all other type 4 installations. The AMI CROIC refers only to installations with a capacity of less than 160 MWhrs per annum. We have defined a special term — 'smart meter' — for the purposes of this F&A, which describes a type 4 meter where it is used instead of a type 5 or type 6 meter and is provided as a monopoly service to residential or small business consumers using up to 160 MWh per annum.[[107]](#footnote-107) This is necessary because the deeming of certain type 4 meters as being type 5 or type 6 equivalents has created potential uncertainty as to the status of these meters when the derogation in clause 9.9C expires, which currently is no later than the end of 2016, unless extended. To further address this uncertainty we have created this classification for the type 5, 6 and smart meter - regulated service.
3. We define the service as follows:

Type 5 or 6 meter or smart meter - regulated service – The service is an alternative control service, if the service is a restoration service provided in accordance with AEMO’s metrology procedure applicable to Victoria, or if the service has been provided by the DNSP since a time when the derogation in clause 9.9C of the NER was in force.

1. This classification is intended to apply to the whole of the 2016-2020 regulatory control period but only where a type 4 meter is installed on other than a competitive basis.[[108]](#footnote-108) Type 4 meters provided on a competitive basis or under an exemption from the derogation are not classified and remain unregulated.
2. Clause 11.17.6(a) of the NER requires the AER to regulate smart meters and their associated equipment in the first year of the next regulatory control period under the form of regulation which applies under the AMI CROIC. The AMI CROIC includes provision for exit and restoration fees. The AMI CROIC also establishes a framework for regulating AMI metering which includes an individual price for meters serving customers in the same customer class. This characteristic is closest to an alternative control service. The AMI CROIC also regulates the price of the service on the basis of a cap on the maximum revenue a distributor may earn for the service. This is implemented through a 'building block' approach. It is subject to a 'true-up' mechanism, whereby variations in actual costs from forecast costs are adjusted in the following two years. The building block approach with an 'unders and overs' adjustment describes the form of control that operates under a revenue cap. In classifying a service the AER must, where there is no previous classification of the service, have regard to the previously applicable service classification.[[109]](#footnote-109) As a consequence of these considerations we have decided to classify this service as an alternative control service and to apply a revenue cap as the form of control. We consider this classification will minimise any disruption to the existing approach to regulating this service. In their respective submissions AusNet Services and Jemena supported this approach whilst CitiPower/Powercor proposed that the service be classified as standard control, but subject to a revenue cap.[[110]](#footnote-110)

Type 5 and 6 and smart meters — unregulated service

1. In their responses to the AER's preliminary position paper the five Victorian electricity distributors each submitted that the AER's classification approach to type 5 and 6 and smart metering services did not adequately address the need for a classification for this group of meter services if competition is introduced in the next regulatory control period.[[111]](#footnote-111) They proposed that there should be a service category for type 5 and 6 and smart metering services provided subject to competition, and that this category should be unclassified.107 We agree. Under the AEMC's Power of Choice Review (discussed further below) it has been proposed to expand competition in metering services. Rule changes to give effect to this policy are under active consideration.[[112]](#footnote-112) As this service will be competitive when introduced the appropriate classification is 'unclassified'. This classification will apply to new metering installations supplied under a competitive framework and involves the provision of metering services by retailers and other parties but not distributors as monopoly service providers. It will therefore not apply to metering installations supplied under the monopoly service arrangements. It will apply to services provided to new customers and to any replacement of an existing meter (except where a meter is supplied as a restoration service).[[113]](#footnote-113)
2. We define this service to be:

Type 5 or 6 meter or smart meter – unregulated service – A service in respect of a type 5 or 6 meter or a smart meter that is not a regulated service as described above is unclassified.

**Meter installation services**

1. In our preliminary positions F&A we proposed to separately classify meter installation services.[[114]](#footnote-114) We now consider that separately classifying a service group specifically for meter installation services is unnecessary. We consider that contestability and efficient pricing is not affected by including meter installation in the broader service group for meter provision, maintenance, reading and data services. As such, we now propose to group type 5 and 6 smart meter installation services with other type 5 and 6 and smart metering services.

Exit fees

1. In our preliminary positions paper we sought comments on the form and scope of an exit fee. We said:

Our expectation is that a fee would be based on the unrecovered cost of existing regulated monopoly provided metering costs and IT systems that would be stranded if a customer elects to obtain a new, competitively supplied meter. As it would be a difficult task to identify the individual cost to be applied in an individual situation as a significant proportion of costs are common to all users we anticipate this will be an average charge.

We received six submissions which addressed this issue. The submissions of DSDBI, AusNet Services, CitiPower/Powercor, Jemena and United Energy all supported an exit fee.[[115]](#footnote-115) The submission of Vector did not.[[116]](#footnote-116) Vector submitted that it considered that an exit fee would be detrimental to competition. The submissions received from other parties submitted that any exit fee should be calculated in a manner consistent with the AMI CROIC, notably clause 7.2. We note that clause 11.17.6(b) of the NER states:

(b) However, for a relevant regulatory control period, services to which exit fees under clause 7, or restoration fees under clause 8, of the AMI Order in Council applied are to be classified as alternative control services and are to be regulated by the AER on the same basis as applied under the AMI Order in Council.

1. We interpret this clause as limiting our discretion. Any fee determined will need to comply with this clause in calculating an exit fee (or a restoration fee).[[117]](#footnote-117) Consequently, we note the comments provided by the respondents and will take these into account in determining the final composition of an exit fee but we consider that an exit fee must apply. We acknowledge Vector's concern to be a valid. However, we consider the appropriate forum to consider this is the AEMC metering competition rule change process, which is separately considering how the NER framework should address this issue.[[118]](#footnote-118) Our intention is, to the extent practicable, to adopt a consistent approach to exit fees in all NEM jurisdictions and to have regard to minimising market distortion effects in applying an exit fee.
2. An important consideration will be to ensure that the Victorian businesses recover the efficient costs of the mandatory rollout program in some way. This outcome may be achieved in a number of ways, some of which may depart from the approach set out in the AMI CROIC. However, unless the Victorian Government determined a different approach should apply, our intention is to apply the approach set out in the AMI CROIC. If the outcome of the process to implement enhanced competition in metering in Victoria resulted in new provisions giving discretion for the AER to not impose an exit fee or to apply an exit fee on a different basis, we would consider that event to be a material change. We would reconsider this position in making the next regulatory determination.

**Meter installation, provision, maintenance, reading and data services**

1. We propose to classify type 5 and 6 and smart metering installation, provision, maintenance, reading and data services when supplied as a monopoly service as direct control services and further, as alternative control services. We consider it necessary to apply a direct form of regulation for the following reasons:[[119]](#footnote-119)

* There is currently a regulatory barrier to any party other than the five Victorian electricity distributors providing type 5 and 6 or smart metering provision, maintenance, reading and data services.[[120]](#footnote-120) Under the rules, only the relevant distributor may install a type 5 or 6 or smart meter in its distribution service area.[[121]](#footnote-121)
* Type 5 and 6 metering services are subject to a direct form of regulation in other NEM jurisdictions.[[122]](#footnote-122)
* There is competition available from type 4 meters.[[123]](#footnote-123)

1. We must further classify type 5 and 6 and smart metering services as standard or alternative control services.[[124]](#footnote-124) We consider these services should be alternative control services because they are provided to specific customers[[125]](#footnote-125) and there is potential for contestability in type 5 and 6 and smart metering services in future.[[126]](#footnote-126)
2. We recognise that the five Victorian electricity distributors are currently the monopoly providers of type 5 and 6 and smart metering services.[[127]](#footnote-127) However, separating the costs of meter installation, provision, maintenance, reading and data services from shared network charges will enhance competition when contestability for these services changes.[[128]](#footnote-128) If charges for these services were bundled in distribution charges, any future changes in contestability may be far less effective.

Another relevant factor we have considered is creating a more transparent and accurate way of providing customers with costing information.[[129]](#footnote-129) Making metering costs transparent under an alternative control classification will allow customers more informed choices on metering installation, provision, maintenance, reading and data services. This is consistent with the current approach under the AMI CROIC.

As previously stated, where type 5 and 6 and smart metering installation, provision, maintenance, reading and data services are supplied on a competitive basis in accordance with the NER or a relevant jurisdictional regulatory instrument the service will be unclassified.

Power of Choice review

1. As set out above, we propose to unbundle type 5 and 6 smart metering services from standard network charges, separate them into different categories of metering services and classify each component as alternative control. Our proposed approach is consistent with the AEMC's final report for its Power of Choice Review.[[130]](#footnote-130) The AEMC designed its recommendations to promote the investment in, and use of, advanced metering infrastructure as has been introduced in Victoria. It considers there will be demand management benefits for customers, retailers and distributors from the use of smart meters.
2. The AEMC recommended metering costs be unbundled from shared network charges.[[131]](#footnote-131) Also, it recommended that provision of metering services be contestable. While we do not determine the contestability of metering services, our proposed approach to classification would facilitate contestability if legislative changes occur to open up the market. The AEMC has recommended that measures to promote contestability for type 5 and 6 metering be pursued. Moreover, a rule change proposal to provide contestability in this service is being considered by the AEMC.[[132]](#footnote-132) Therefore, we are confident that our approach to unbundle type 5 and 6 and smart metering services will complement potential legislative changes to make these services contestable.[[133]](#footnote-133)
3. Based on the analysis above, our proposed approach is that it is clearly more appropriate to classify type 5 and 6 and smart metering services as alternative control. Our proposed approach is consistent with our position set out in the preliminary positions F&A.

Type 7 metering services

1. A type 7 metering service does not measure the flow of electricity. Rather, a type 7 'metering' service consists of estimating the amount of electricity used by, for example, public lights or traffic lights. Distributors charge customers, usually councils or government agencies, for unmetered connections by estimating the usage using standard data. 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. As only distributors estimate usage, only they can bill customers.
2. The five Victorian electricity distributors are the monopoly providers of type 7 metering services. This is because, as indicated above, the cost of providing type 7 metering services is nominal.[[134]](#footnote-134) For this reason, an alternative provider has limited incentive to enter the market for the provision of type 7 metering services. The five Victorian electricity distributors are already performing data management services for type 5 and 6 and smart meters. Providing type 7 metering services is a logical extension for the five Victorian electricity distributors to undertake.
3. Citelum proposed that the AER consider classifying this as a negotiated service.[[135]](#footnote-135) They suggest that by agreement in accordance with clause 7.13 of the NER improved processes for estimating the energy consumption of type 7 metering installations could be implemented. The Street Lighting Group of Councils (SLG) submitted that:

…there is no monopoly characteristic to this service.[[136]](#footnote-136)

1. We do not accept that clause 7.13 can apply to this process without a change in the market procedures. We also do not agree with the SLG there is no monopoly characteristic to the service. As is the case for all metering data used in market settlements, the estimation of the energy use of a type 7 metering installation is subject to the AEMO metrology procedures.[[137]](#footnote-137) The metrology procedures are very detailed and specify (amongst other things) that the responsible person must prepare the data for each applicable metering installation type. This role is allocated by each jurisdiction to specific bodies. This is not a matter over which the AER has any control. Consequently, although external parties may prepare input information, its subsequent processing is restricted to the parties qualified under the AEMO procedures, namely the five Victorian electricity distributors. This is not a matter that can be changed by agreement. Compliance with AEMO procedures is mandatory.[[138]](#footnote-138)
2. Consequently, we consider that there is no potential to develop competition in the provision of type 7 metering services.[[139]](#footnote-139) Within a distribution licence area a distributor must account for all energy consumed. As noted above, under the metrology procedures a distributor must report accurate energy data to the market operator for use in the market settlement systems. This data is also a component of the data used in the calculation of distribution loss factors, which are regulated by the AER.[[140]](#footnote-140) As type 7 metering installations are directly connected to the distribution system the distributor has need to make these calculations for these purposes, both of which have monopoly characteristics. Therefore, we intend to classify type 7 metering services as direct control services. In terms of our further classification as either standard control or alternative control services, we can see no reason to change from the current classification—alternative control. Any costs associated with type 7 metering services are minimal. As such, we consider a different approach to the current classification is not 'clearly more appropriate.'[[141]](#footnote-141)
3. Therefore, our proposed approach is to continue to classify type 7 metering services as alternative control services. Our proposed approach differs from our position set out in the preliminary positions paper F&A for Victoria. In appendix B we correctly listed the classification as alternative control but this was incorrectly stated to be standard control in section 1.3.3. We have corrected this inconsistency.

Auxiliary metering services

1. The five Victorian electricity distributors also provide a range of metering related services to customers on request. Examples include customer requested meter tests, additional meter reads or equipment alterations. We propose to group these metering services together as 'auxiliary metering services'.
2. We think contestability in auxiliary metering services is limited by the monopoly nature of the provision of type 5 and 6 and smart metering services, to which most auxiliary metering services relate.[[142]](#footnote-142) For example, only the five Victorian electricity distributors can perform an additional meter read as the monopoly provider of type 5 and 6 and smart meter reading services.[[143]](#footnote-143) For this reason, we propose to classify auxiliary metering services as direct control services.
3. Having decided to apply a direct control classification, we must further classify auxiliary metering services as either standard control or alternative control. Because the five Victorian electricity distributors provide auxiliary metering services to specific customers, we propose to classify them as alternative control services.[[144]](#footnote-144)
4. Under our proposed approach, customers using auxiliary metering services will pay for the services they use. To the extent that the provision of auxiliary metering services is contestable, or may become contestable, our proposed approach would facilitate this.

Metering classification summary

1. On the basis of our above analysis, our proposed approach is to classify metering services as summarised in table 6.
2. Table 6: AER's proposed approach to classifying metering services

|  |  |
| --- | --- |
| **AER's proposed approach** |  |
| Service | Proposed classification | |
| Metering type 1 to 4 (excluding smart meters) | Unclassified |
| Type 5 and 6 and smart metering services - regulated service (i.e. metering provision not subject to competition) | Alternative control |
| Type 5 and 6 and smart metering services - unregulated service (i.e. metering provision subject to competition) | Unclassified |
| Metering type 7 | Alternative control |
| Auxiliary metering services | Alternative control |

Source: AER

### Ancillary network services

For classification purposes, we propose to replace the current service groups called 'fee based services' and 'quoted services' with a service group called 'ancillary network services'.[[145]](#footnote-145)

The existing 'fee based services' and 'quoted services' groupings describe the basis on which service prices are determined. We consider all of these services should be classified in a similar manner, regardless of how their regulated prices are determined.

Ancillary network services share the common characteristic of being non-routine services provided to individual customers on an 'as needs' basis. Examples include customer requested appointments or after hours service provision. Ancillary network services involve work on, or in relation to, parts of the Victorian distributor's distribution network. Therefore, as with network services, only the distributor can perform these services.

We consider that, as with network services, there is a regulatory barrier preventing any party other than the five Victorian electricity distributors providing ancillary network services.[[146]](#footnote-146) 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. Furthermore, the scale of resources used by the distributors to provide ancillary network services also likely prevents alternative providers from competitively providing them.[[147]](#footnote-147) These factors contribute to our view that, like network services, the five Victorian electricity distributors possess significant market power in providing ancillary network services.

Because of these barriers to competition from alternative service providers, we propose to classify ancillary network services as direct control services.[[148]](#footnote-148)

Having decided to apply a direct control classification, we must further classify ancillary network services as either standard control or alternative control. We intend to classify ancillary network services as alternative control because they are attributable to individual customers.[[149]](#footnote-149) We adopt this view even though ancillary network services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the administrative costs to us, the distributors, users or potential users.[[150]](#footnote-150) This is because classifying ancillary network services as alternative control services is consistent with the current approach.

The nature of ancillary network services is that the customer requesting the service will benefit from that service. As such, the costs of that ancillary network service are directly attributable to an individual customer.[[151]](#footnote-151) This results in costs that are more transparent for customers. Additionally, the note to clause 6.2.2(c)(5) of the rules states:

In circumstances where a service is provided to a small number of identifiable consumers on a discretionary or infrequent basis, and costs can be directly attributed to those consumers, it may be more appropriate to classify the service as an alternative control service than as a standard control service.

1. For these reasons, we intend to classify ancillary network services as alternative control services in the next regulatory control period.

### Public lighting

1. AusNet Services, CitiPower, Jemena, Powercor and United Energy operate and maintain public lighting throughout the state as part of their distribution networks.[[152]](#footnote-152) The distributors provide these services to local councils and state government departments responsible for public lighting. The rules do not define public lighting service, however, they are defined in the Victorian Public Lighting Code which is administered by us.[[153]](#footnote-153) Also, we have consistently defined the following public lighting services in other distribution determinations as the:

* 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.[[154]](#footnote-154)

1. in our preliminary positions paper we proposed to continue to include emerging public lighting technology (emerging technology) as part of the public lighting services group (but to classify it separately). As a distribution service, public lighting assets may be upgraded from time to time, just as any other network asset may be upgraded for better service delivery or improved efficiency.
2. In the case of public lighting, evolving technology is producing new luminaries using less electricity than older assets. One example of this trend is the rapid development of LED technology. Emerging technology relates to luminaires that the Victorian distributors do not provide or which may not exist at the time of our distribution determination. New lighting technology has increasingly become available during the current regulatory period and we expect this trend to continue in the next regulatory control period. A service distinction must also be made for greenfield sites, such as new housing estate developments. Greenfield sites are contestable under the Victorian Public Lighting Code. 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.

Public lighting (excluding emerging technology and greenfield sites)

Our position is to classify public lighting (excluding emerging technology and greenfield sites) as a direct control service and further, as alternative control. This is consistent with our current approach.

In our preliminary positions we sought comments on whether there was a case to consider classifying all public lighting as a negotiated service. However, we also stated our preference was to continue with the current approach. In support of that decision we said:

While the Victorian distributors do not have a legislative monopoly over these services, a monopoly position exists to some extent.[[155]](#footnote-155) This is because the Victorian distributors own the majority of public lighting assets.[[156]](#footnote-156) That is, other parties would need access to poles and easements for instance to hang their own public lighting assets. However, the Victorian distributors own and control such supporting infrastructure. There are also safety restrictions on the qualifications of electrical workers in close proximity to overhead power lines. Therefore, similar to network services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the Victorian distributors.[[157]](#footnote-157) Based on the above analysis, our preliminary position is to classify public lighting services, excluding emerging technology, as direct control services.[[158]](#footnote-158) This is consistent with its current classification.[[159]](#footnote-159)

We received submissions from Citelum and the Streetlight Group of Councils (SLG) that challenged whether the monopoly characteristics cited by the AER exist and whether the preliminary classification was justified.[[160]](#footnote-160) The submissions each set out a detailed analysis of the operation of the current framework for implementing new technology and provide detailed commentary on difficulties experienced with the current scheme. We respond to these submissions in appendix A. The SLG proposed reclassification of all public lighting as a negotiated service, as a step towards an eventual 'unclassified' categorisation.[[161]](#footnote-161)

Monopoly service

First we will discuss in greater detail the basis of our conclusion that the Victorian distributors do have a monopoly over legacy street lighting installations and assets built to the Victorian Electricity Supply Industry (VESI) construction standard.

Under the Public Lighting Code street lighting can be built to one of two standards. The VESI standard, which is simpler and therefore cheaper to build, own and operate or to the general wiring standards that apply to all other electricity installations. The VESI standard relies on the protection and isolating components inbuilt into the distributor's network to protect the installation against electricity hazards and also allows that a streetlight is not individually metered (it is subject to type 7 metering). This distinction is explained in some detail in the AusNet Services submission.[[162]](#footnote-162) The general wiring standard imposes exacting requirements on every installation to have isolation equipment and fault protection devices inbuilt and for the installation to be individually metered. The general wiring standard is inevitably more expensive to build, own and operate but installations to this standard need not be owned by the distributor. Under safety legislation the VESI standard is only available to an electricity distributor to operate and maintain.

Citelum and the SLG build arguments that, by using qualified contractors, it would be possible to open up the advantages of the lower VESI standard to the customers who must pay for street lighting. However, this does not mean 3rd party contractors can access installations built to the lower VESI standard without the active supervision of the electricity distributor. The AER is not the regulator of electrical safety in Victoria. This is a role served by Energy Safe Victoria. Under these arrangements each distributor must have an Electrical Safety Management Scheme (ESMS). Through these mandatory safety schemes a heavily controlled framework for safe access to its network is imposed on each distributor.

We must have regard to the safety regulation framework as its exists in each jurisdiction. We consider that some scope probably exists for distributors to introduce more flexible arrangements to make this service more open to competitive provision. Over time, by improving their consultation with customers, we expect some progress will be made in this regard. We note that AusNet Services advised that it has accredited 18 suppliers of construction services.[[163]](#footnote-163) However, the scope to increase contestable provision does not alter the fundamental premise that the service has a monopoly element that arises from these safety considerations. Having determined that the service does have a monopoly characteristic, we classify the service as a direct control service.

Emerging technology and greenfield sites (new public lighting)

Our preliminary position on emerging technology and greenfield sites was to continue the existing classification as a negotiated service. The SLG submitted this service should be unclassified.[[164]](#footnote-164)

Citelum submitted the current regime for implementing new technology in lighting is slow, cumbersome and expensive in Victoria, especially when compared to other States.[[165]](#footnote-165) We are concerned that the approval process does not appear to be operating efficiently in Victoria. The cause of this inefficiency is not identified. We expect regulated businesses to work actively with their customers to find ways to deliver services efficiently. If the processes of the Victorian distributors can be improved to address or mitigate this concern we would support those improvements.

In our preliminary positions paper we noted that the approvals process exists because of the need to satisfy safety, quality and energy usage requirements before the luminaires can be connected to the distribution network.[[166]](#footnote-166) We went on comment that the difficulties experienced with implementing new technology tended to confirm that there remains a role for distributors in relation to many types of public lighting. Consequently, there also remains a case for some regulatory oversight. This supports our overall view the service should be classified.

Were the service to be moved to either standard control or alternative control we believe the effect would be to add an additional layer of economic regulation to the factors which currently slow the adoption of emerging technologies. Consequently, we consider the emerging technologies and greenfield sites service should continue to be a negotiated service. We include non-standard lights not owned by the DNSP in this service.

Unbundling charges for operation, maintenance repair and replacement

We posed the question in our preliminary positions paper: 'Could public lighting be a negotiated service?'[[167]](#footnote-167) The submissions of the SLG and United Energy addressed this question. The SLG proposed we split public lighting into 11 services with seven services classified as negotiated and four as unclassified.[[168]](#footnote-168) The SLG proposes this apply to all public lighting. United Energy defined two classes of operation, maintenance and repair/replacement (OMR) services for public lighting. One class is for assets dedicated to a particular customer (dedicated public lighting assets) and a second class for luminaires connected to the shared distribution network (shared public lighting assets). United Energy proposed we create two services classified as negotiated, but only in relation to the first class — i.e. assets dedicated to a particular customer.[[169]](#footnote-169) United Energy explained that the OMR charge is currently is a smeared average charge across all Councils. United Energy further submitted that unbundling the charge for replacement of luminaires connected to the shared network would be problematic. The reason stated was because each Council has a different asset type profile and age profile and thus, there would be 'winners and losers' in unbundling the charge. United Energy also explained that its proposal would be a significant reform that took into account the safety issues that are inherent in public lighting design, installation and operation.

We think that in the longer term that the SLG proposal has merit. However, as we have explained above, we consider there remains a significant monopoly element associated with some of the services due to the safety aspects of working in close proximity to overhead powerlines for many installations and also, because of the safety issues associated with the different design standards that have traditionally applied. We consider these safety issues are capable of resolution over time but we must apply our classification decisions having regard to the legislative framework as it currently exists. However, as United Energy has identified, the Public Lighting Code does not require that distributors to own and/or replace existing public lights (other than where there are safety issues). The submission of Citelum makes a similar assessment of the Public Lighting Code requirements.[[170]](#footnote-170) Reforms which empower consumer choice should be embraced. Consequently, we accept the United Energy proposal to split the OMR service into three components as follows:

Table 7: AER classification of public lighting OMR charges

|  |  |  |
| --- | --- | --- |
| Service |  | Classification |
| Dedicated public lighting assets | Operation, maintenance, repair | Negotiated |
| Dedicated public lighting assets | Replacement | Negotiated |
| Shared public lighting assets | Operation, maintenance, repair, replacement | Alternative control |

Source: AER

1. The split proposed by United Energy separates the monopoly service element from a component for which competitive provision is feasible. We think this split is justified. Although the submissions from customers sought to extend reclassification to all services we do not think this can sustained under the current regulatory arrangements. We consider that our approach will enable distributors to offer this service on competitively derived terms and prices that reflect true cost of the service. We also note that there is an expectation of tariff reforms being implemented in time for the next Victorian distribution revenue determination.[[171]](#footnote-171) Unbundling these services will be consistent with tariff reform.

Service classification

The services for shared public lighting assets has been identified as having a monopoly characteristic. We therefore classify them as direct control services. As direct control services, we must further classify public lighting services as either standard control or alternative control services.[[172]](#footnote-172) Our position is to classify shared public lighting assets as an alternative control service, consistent with current arrangements. The services for dedicated public lighting assets, emerging technology and greenfield sites have substantial scope for contestable provision by alternative suppliers but require close cooperation with the distributors to implement effectively. We therefore classify these services as negotiated services.

This approach provides scope for third parties and new entrants to provide public lighting services for new public lighting assets into the future. Hence, it may encourage other potential service providers to enter the market in future if the safety matters discussed above can be resolved.[[173]](#footnote-173) For the shared public lighting assets, emerging technology and greenfield sites services there would be no material effect on administrative costs to us, Victorian distributors, or users or potential users, because we are retaining the current classification.[[174]](#footnote-174) Although administrative costs will be incurred by us, the Victorian distributors, or users or potential users of the dedicated public lighting assets service to implement the changed service classification, we consider the benefits of competitive provision will outweigh these costs.[[175]](#footnote-175) The Victorian distributors can directly attribute the costs of providing shared public lighting services to a specific set of customers, such as local government councils.[[176]](#footnote-176)

### Additional classification issues

Non-traditional investments

1. United Energy sought clarity on the regulatory treatment of non-traditional network investments.[[177]](#footnote-177) These investments include, among other things, battery storage on feeders experiencing voltage issues or requiring capacity augmentation, load control devices and distributed generation. United Energy notes that there are some key difference between these non-traditional investments and traditional investments, including that:

* non-traditional investments may in some cases be competitively provided and owned by third parties, and
* non-traditional investments may not form part of or meet the full definition of the 'distribution system as currently provided under the rules (for example, they could be located on the customer's premises).

1. These differences aside, United Energy considers that these investments should be treated in a similar way to traditional network investments. In particular, United Energy considers that the cost of these investments should be shared by all customers through DUOS charges. In some instances, others may own these investments and, therefore, they are not included in United Energy's Regulated Asset Base. United Energy is seeking to fund these services through an operating expenditure allowance or a revenue adjustment.

We do not consider it necessary to classify a service for non-traditional investments. This activity is directly concerned with the provision of network services, which is a classified service. Our expectation is that businesses will, in their day-to-day operations, consider the most efficient means of delivering regulated services. We consider that the rationale for an operating expenditure allowance or revenue adjustment is contingent on the business case for a particular investment. If the purpose of the investment is to efficiently deliver a network service, the expense should qualify as operating expenditure where the service is obtained through a contractual arrangement.

United Energy has questioned whether assets installed in a customers' premises would still form part of a distribution system. We consider that they will for the following reason. When a distributor (or any other third party) installs an electrical asset within a customer's premises we consider that this will result in the customers' wiring becoming an embedded network, which is also a special type of distribution system. This is because the NER definition of a distribution system is traceable to the ownership of physical assets. When the customer's wiring becomes an 'embedded network', under clause 2.5.1 of the NER it is subject to registration as a network with AEMO or to exemption from registration by the AER. Consequently, the investment by the NSP in assets installed within the customer's premises would continue to form part of a distribution system as defined in the NER.[[178]](#footnote-178) If the investment is associated with a demand management project, the embedded network would be deemed to be exempt under the AER's guideline for exemption from registration of an electricity network.[[179]](#footnote-179) Otherwise, the customer would need to seek an individual network exemption from the AER.

## AER's service classification approach

1. In summary, we intend to group and classify the distribution services supplied by AusNet Services, CitiPower, Jemena, Powercor and United Energy as set out in table 8. Appendix B sets out a list of the five Victorian electricity distributors' distribution services and our proposed classifications.

Table 8: Proposed distribution service classifications – summary

|  |  |  |
| --- | --- | --- |
| AER service group | Proposed classification of distribution services | Proposed classification of direct control services |
| Network services |  |  |
| All | Direct control | 1. Standard control |
| Connection services |  |  |
| Routine connections (not requiring augmentation) | Direct control | 1. Alternative control |
| New connections requiring augmentation. | Direct control | 1. Standard control |
| Temporary connections and disconnections | Direct control | 1. Alternative control |
| Inspection of PV installation site | Direct control | 1. Alternative control |
| Energisation and de-energisation | Direct control | 1. Alternative control |
| Supply enhancement at customer request | Direct control | 1. Unclassified |
| Operate and maintain connection assets (captured as network services) | Direct control | 1. Standard control |
| Customer initiated undergrounding and/or rearrangement of distribution assets serving that customer | Direct control | 1. Standard control |
| Ancillary network services |  |  |
| 1. Supply abolishment < 100 amps | 1. Direct control | 1. Standard control |
| Reserve feeder construction | Negotiated |  |
| Possum guards | Unclassified |  |
| Emergency recoverable works | Unclassified |  |
| Installation, repair, and maintenance of watchman lights | Unclassified |  |
| All other services | Direct control | Alternative control |
| Metering services |  |  |
| Types 1 to 4 (excluding smart meters) | Unclassified |  |
| Types 5, 6 and smart meters - regulated service | Direct control | Alternative control |
| Types 5, 6 and smart meters - unregulated service | Unclassified |  |
| Type 7 | Direct control | Alternative control |
| Auxiliary metering services – alternative control | Direct control | Alternative control |
|  |  |  |
| Public lighting services |  |  |
| Operation, maintenance, repair and replacement - shared public lighting assets | Direct Control | Alternative control |
| Operation, Maintenance and Repair - dedicated public lighting assets | 1. Negotiated |  |
| Replacement - Dedicated public lighting assets | 1. Negotiated |  |
| New public lights (that is, new lighting types not subject to a regulated charge and new public lighting at greenfield sites) | 1. Negotiated |  |
| Alteration and relocation of public lighting assets | 1. Negotiated |  |

Source: AER

# AER-final-orangeControl mechanisms

1. This attachment sets out our decision, together with our reasons, on form of control mechanisms to apply to the five Victorian electricity distributors' direct control services for the 2016–20 regulatory control period. This attachment also sets out our proposed approach on the formulae to give effect to the control mechanisms for direct control services.
2. Our distribution determination must impose controls over the prices (and/or revenues) of direct control services. 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.
3. Attachment 1 provides our proposed classification of Victorian electricity distribution services. Broadly, we will classify a service as a direct control service if the distributor is a natural monopoly provider of the service. Typically, we split direct control services into standard and alternative control services based on the customer base for the service. For example, if the broad customer base benefits from a service, we will classify it as a standard control service. If a distributor only provides a service to specific customers, or if there is potential for competition to develop in the provision of that service, we will classify it as an alternative control service.
4. The form of control mechanisms must be as set out in our F&A paper.[[180]](#footnote-180) 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 our F&A paper, unless we consider that unforeseen circumstances justify departing from the formulae set out in that paper.[[181]](#footnote-181)

## AER's decision

1. We have decided to apply the following forms of control in the 2016–20 regulatory control period:

* Revenue cap— for services we classify as standard control services.
* Revenue cap— for regulated metering (not subject to competition) services we classify as alternative control services.
* Caps on the prices of individual services— for services we classify as alternative control services and a fee can be set at the determination.

## AER's assessment approach

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

* the form of the control mechanisms[[182]](#footnote-182)
* the formulae to give effect to the control mechanisms
* the basis of the control mechanism[[183]](#footnote-183)

1. The rules set out the control mechanisms that may apply to both standard and alternative control services:[[184]](#footnote-184)

* 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. Distributors comply 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[[185]](#footnote-185)

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

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

A revenue cap sets a total revenue allowed for each year of the regulatory control period. Distributors must then recover revenue equal to or less than the total revenue. Distributors comply 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 total revenue. 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 total revenue in future years. This operation occurs through an 'overs and unders' account, whereby any over-recovery (under-recovery) is deducted from (added to) the total revenue in future years.

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

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

* revenue yield control (average revenue cap)

An average revenue cap is a cap on the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the total revenue by a particular unit (or units) of output, usually kilowatt hours (kWh). The distributor complies with the constraint by setting prices so the average revenue is equal to or less than the total revenue 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 proposed approach, we have not considered a schedule of fixed prices or caps on the prices of individual standard control services. This is because we consider these direct price control mechanisms do not provide the level of flexibility within the regulatory control period for distributors to manage distribution use of service charges shared across the broad customer base. Consequently, our assessment approach is focussed on a revenue cap or WAPC.

### Standard control services

1. In determining a control mechanism to apply to standard control services, we will have regard to the factors in clause 6.2.5(c) of the rules:

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

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

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

The basis of the control mechanism for standard control services must be of the prospective CPI–X form or some incentive-based variant.[[186]](#footnote-186)

1. The following sections outline our consideration of each of the above factors in determining our proposed form of control for standard control services.

Need for efficient tariff structures

1. Broadly, we consider prices are efficient if they reflect the underlying cost of supplying distribution services and take into account customers’ willingness to pay.
2. Efficient pricing is important for several reasons:

* Where prices are cost reflective, allocative efficiency is maximised because consumers can compare the cost of providing the service to their needs and wants.[[187]](#footnote-187)
* 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.
* Cost reflective prices allow distributors to make efficient investment decisions. Because consumers base consumption decisions on the cost of providing the service compared to their value of consumption, increases and decreases in demand signal the potential need for extra network capacity.

Administrative costs

1. Where possible, a control mechanism should minimise the complexity and administrative burden for us, distributors and users.

Existing regulatory arrangements

1. We consider that consistency in regulatory arrangements across regulatory periods for similar services provided by a distributor is generally desirable.

Desirability of consistency between regulatory arrangements

1. We consider that consistency within and across jurisdictions for similar services is generally desirable.

Revenue recovery

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

Pricing flexibility and stability

1. Price flexibility enables distributors to restructure existing prices and/or introduce charges for new services.
2. The stability and predictability of distribution network prices is important because it affects consumers’ ability to manage bills and retailers' ability to manage risks incurred from changes to network prices.

Incentives for demand side management

1. Demand side management refers to the implementation of non-network solutions to avoid the need to build network infrastructure to meet increases in annual or peak demand.[[188]](#footnote-188)

### Alternative control services

1. In determining a control mechanism to apply to alternative control services, we will consider the factors in clause 6.2.5(d) of the rules:

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

We propose that another relevant factor is the provision of cost reflective prices. Efficient prices or cost reflectivity allows consumers to compare the cost of providing the service to their needs and wants. Cost reflective prices also allow distributors to make efficient investment and demand side management.

1. We must state what the basis of the control mechanism is in our distribution determination.[[189]](#footnote-189) This may utilise elements of Part C of chapter 6 of the rules with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass-through mechanism.

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

1. We consider that a revenue cap best meets the factors set out under clause 6.2.5(c) of the rules. We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and better alignment with the introduction of efficient prices. Furthermore, we consider that the detriments of a revenue cap – within period pricing instability and weak pricing incentives – are able to be mitigated. We provide our consideration of these issues below.

### Efficient tariff structures

Broadly, we consider that efficient prices incorporate two key characteristics:

* the underlying cost of supply
* the willingness of customers to pay.

While there are a variety of methods of incorporating these characteristics, we consider that the resulting prices from each will include many of the same features. First, for the majority of distributors the costs of supply are fixed or relate to peak demand, so efficient prices will be structured around fixed or peak prices.[[190]](#footnote-190) Second, because customers’ willingness to pay for connection to the network is generally higher than for electricity consumption, the largest margin (above the cost of supply) is likely to be applied to fixed (connection) prices.

1. We note that similar to other jurisdictions (regardless of control mechanism) the five Victorian electricity distributors recover significant revenue from flat energy tariffs which are unrelated to the peak periods of demand by time or location.

We consider that by itself the revenue cap provides limited incentive for distributors to set efficient prices. That is, under a revenue cap, distributors' revenues are fixed over the regulatory control period. Distributors therefore maximise profits by decreasing costs. To maximise profits, distributors face an incentive to increase prices above marginal costs on price sensitive services, thereby reducing demand for those services. United Energy made a significant submission on this point.[[191]](#footnote-191) We accept that the United Energy arguments in favour of a WAPC are theoretically sound. DSDBI also commented on this topic in a similar vein. In their submission, the Victorian Government did not support a revenue cap and submitted that a WAPC control mechanism should be considered.[[192]](#footnote-192) DSDBI said:

… the form of price control must support the implementation of more efficient pricing structures…[[193]](#footnote-193)

1. However, earlier DSDBI also noted:

…it is not a clear cut decision to use one form of price control over another…[[194]](#footnote-194)

1. We agree it important to encourage a more efficient pricing structure. However, we consider that a revenue cap is unlikely to give rise to inefficient pricing for the five Victorian electricity distributors. A revenue cap should not discourage a business from utilising peak-based pricing, even if a WAPC is as good or better in this regard. We consider that the majority of distributors' variable costs are caused by augmentations and connections (where demand for connections is likely to be price insensitive) to the network. The incentive for distributors to decrease costs through pricing is therefore likely to result in higher prices for peak demand. This would require a shift towards peak energy/capacity based tariffs. In the current environment where tariffs largely consist of flat energy/capacity tariffs we consider that a shift towards peak energy/capacity prices will result in increases in pricing efficiency, regardless of the form of control.[[195]](#footnote-195) That is, the recent scenario of rising peak demand and falling energy consumption is a strong driver of a need to reform tariffs under both a revenue cap and a WAPC.

### Administrative costs

We consider that there is little difference in administrative costs between control mechanisms under the building block framework in the long run. However, we note that a change from a WAPC to a revenue cap would likely result in increased administrative costs in the short run. Under a WAPC revenue is variable within the regulatory control period which results in higher risk to distributors. This would likely lead to increased costs through risk minimisation strategies. Furthermore, the introduction of a revenue cap in Victoria will likely lead to reduced administrative costs to users and us due to consistency across regulatory arrangements. The introduction of a revenue cap in South Australia/New South Wales will be under a revenue cap in 2014–2019. Queensland will be under a revenue cap from 2015–2020. Tasmania is already operating under a revenue cap. This consistency will reduce administrative costs for us through standardisation of modelling approaches, incentive schemes and consultation requirements.

### Existing regulatory arrangements

1. We consider that consistency across regulatory arrangements for relevant services is generally desirable. We consider that this factor needs to be weighed against the other factors under clause 6.2.5(c) of the rules. We consider this is appropriate because consistency in and of itself has no direct effect on distributors, us or customers.

### Desirability of consistency between regulatory arrangements

1. We consider that consistency between regulatory arrangements is generally desirable but is not primary to our considerations in this instance. Consistent regulatory arrangements need to be weighed against the other factors under clause 6.2.5(c) of the rules. Pursuing the other factors produces outcomes that better achieve the national electricity objective and are consistent with the revenue and pricing principles.

### Revenue recovery

1. We consider that a revenue cap provides a high likelihood of efficient cost recovery. We consider that because costs for distributors are largely fixed and unrelated to energy sales, revenue recovery should also be largely fixed and unrelated to energy sales. We note that differences from forecast peak demand and customer numbers may cause differences in distributor costs. Where this occurs, variations from efficient cost recovery may result under the revenue cap. We have therefore considered adjustment mechanisms (hybrid control mechanisms) to the revenue cap for variations from forecast peak demand and customer numbers. Section 1.3.8 outlines our consideration of hybrid control mechanisms.
2. We consider that a WAPC does not provide a high or even reasonable likelihood of efficient cost recovery. We consider the WAPC provides an opportunity for distributors to recover revenue systematically above forecast. That is, under a WAPC distributors have the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast quantities, and to recover revenue close to forecast when actual quantities are below forecast quantities. We adopted a similar position and reasoning in New South Wales.[[196]](#footnote-196)

### Pricing flexibility and stability

Pricing flexibility

1. We consider that price flexibility for existing tariffs and tariff structures is similar for all forms of control and that it is influenced by the side constraints and the pricing principles in the rules.
2. We consider that the revenue cap results in increased pricing flexibility in relation to the introduction of new tariffs and tariff structures. Under a revenue cap, to introduce a new tariff or tariff structure distributors are required to submit reasonable forecasts for that tariff. As there is no revenue at risk because revenue is fixed over the regulatory control period, the incentive to manipulate such forecasts is low. Conversely, under a WAPC, distributors submit reasonable estimates when introducing new tariffs or tariff structures. Given that substantial revenue is at risk, we assess these estimates rigorously which can result in significant changes in profit for distributors. We consider that this is likely to be of increasing importance under changes to the pricing principles proposed by SCER.[[197]](#footnote-197)

Pricing stability

1. We consider price instability can occur under all forms of control mechanisms. This is because the rules require various annual price adjustments regardless of the control mechanism.[[198]](#footnote-198)
2. We consider that there is increased likelihood of overall price instability within a regulatory control period under a revenue cap. That is, the distributors must adjust prices during the regulatory control period to account for differences between forecast and actual sales volumes. The difference is added to what is called an unders and overs account. The balance of this account is then added to future revenue requirements to make certain the revenue cap is achieved. Generally the balance of the unders and overs account is adjusted for in full at the first opportunity. However, when the account exceeds certain limits (tolerance limits), the adjustment may be made over two or more years. We consider that tolerance limits and the design of the unders and overs account can limit price adjustments in any one year. For example, in Queensland in the current period, we applied tolerance limits to the unders and overs account. In Tasmania,[[199]](#footnote-199) we designed the unders and overs account as a rolling account with an estimate year to help smooth the price adjustments year on year.[[200]](#footnote-200) We also consider that incorporating forecast sales in forming the X-factors in the distribution determination will result in lower balances in the unders and overs account.[[201]](#footnote-201)
3. We consider the WAPC can increase overall price stability within the regulatory control period compared to a revenue cap. However, a WAPC is unlikely to lead to increased price stability or predictability for individual tariffs or customers. Under a WAPC distributors face an incentive to   
   re-balance tariffs to maximise profit and this incentive may result in large changes to tariffs within the regulatory control period.
4. We also consider that the WAPC can result in greater price instability across regulatory control periods compared to the revenue cap. This is particularly prominent if a trend of falling volumes has set–in throughout the regulatory control period, prompting a large upward adjustment in the X-factors (and hence prices) for the next regulatory control period under the WAPC. 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).
5. Victorian electricity prices have risen sharply in recent years. We consider that the main concern of customers in all jurisdictions is likely to be price volatility rather than changes to a distributor's revenue requirements. This rising price trend has also been experienced in Queensland, which operated on a revenue cap over the same period. In our decision on the Queensland Framework and Approach we discussed in some detail how the size of the 'unders and overs' account, which is an integral component in the implementation of a revenue cap, had had an insignificant effect on price outcomes.[[202]](#footnote-202) The factors that contributed to steep increases in Queensland electricity prices are identified to be:

* substantial increases in network investment
* adjustments made by the Australian Competition Tribunal[[203]](#footnote-203)
* adjustments to incorporate solar feed-in tariffs.
* increases in the fixed 'service charge' in 2013.

1. Importantly, the contribution to price volatility due to errors in the recovery of revenue from year–to–year through the unders and overs account was insignificant.
2. A further aspect to consider is the effect on price volatility stemming from the form of control between regulatory control periods. In moving from one regulatory control period to the next, a WAPC would likely subject consumers to large price increases if there are demand forecasting errors. That is, under a WAPC distributors have the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast quantities. Similarly, they are able to recover revenue close to forecast when actual quantities are below forecast quantities. The revenue cap avoids this as demand only forms a small component of forecasting revenue requirements. This results in less price volatility and therefore less movement in prices for consumers between regulatory control periods.

### Incentives for demand side management

1. We consider a revenue cap provides an efficient incentive to undertake demand side management.
2. Under a revenue cap we fix distributors' revenue over the regulatory control period. Distributors can therefore increase profits by reducing costs. This creates an incentive for distributors to undertake demand side management projects that reduce total costs. That is, any demand side management project where the reduction in network expenditure is greater than the cost of implementing the demand side management. We consider this provides an efficient incentive to distributors to undertake demand side management within a regulatory control period.
3. Under a WAPC a distributor's profits are linked directly to the actual volumes of electricity distributed. This is because, in practice, distributors have chosen energy based network tariffs in most instances. This means that even when implementation of a demand side management project would reduce a distributor's total costs it will likely face a disincentive to undertake the project because the costs of implementation plus the reduction in revenue will outweigh the reduction in network expenditure.

### Hybrid form of control

1. We consider that higher administrative costs to distributors and us under a hybrid revenue cap outweigh its potential benefits.
2. There are a number of different ways to design a hybrid form of control mechanism. We have considered a hybrid revenue cap where revenue is adjusted within the regulatory period to adjust for deviations from forecast cost drivers. That is, customer numbers and peak demand. This design enables distributors' revenues to align more closely to the cost drivers compared with a revenue cap. However, it may be difficult to develop an effective revenue function under a hybrid revenue cap. Under the hybrid revenue cap we must recalculate the distributors' maximum allowable revenue each year. This would involve substantial administrative costs to distributors and us throughout the regulatory control period. Additionally, because a large proportion of distributors' costs are fixed rather than variable such adjustments may only result in small adjustments to distributors' maximum allowable revenues. For these reasons, the Independent Pricing and Regulatory Tribunal (NSW) moved away from a hybrid revenue cap to a revenue cap in the 1999–2004 distribution determination.[[204]](#footnote-204) Other regulators (Queensland Competition Authority and the Office of the Tasmanian Economic Regulator) also noted the difficulties and complexities involved in developing and applying a hybrid revenue cap.[[205]](#footnote-205)

### Formulae for control mechanism

1. 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.[[206]](#footnote-206) We must include the formulae in our final F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A.[[207]](#footnote-207)
2. Since our preliminary position paper, we have added an adjustment to our formula. In particular, the five Victorian electricity distributors submitted that as the incentive component for the STPIS operates as a percentage of revenue it therefore should be expressed as a multiplicative term, rather than as additive. We consider that either approach is viable. So long as the STPIS adjustment is calculated correctly it may be undertaken as a stand-alone calculation and added to the other building block components or it may be incorporated directly in the formula. However, we agree that when calculated as a multiplication the change in values is easier to identify and reconcile than as an additive term.
3. A second matter is that the AER formula for the calculation of MAR as a revenue cap (equation 1) was incorrectly expressed as a mathematical identity.[[208]](#footnote-208) We agree the better form of expression is as an inequality. That is, the revenue achieved from the sum of all sources must be less than or equal to the revenue cap, not simply equal the revenue cap. We do not think this change is significant. In practice this calculation is rarely precise. The discrepancy between the actual value and the target value is dealt with through an 'unders and overs' adjustment.
4. Below is a proposed formula to apply to standard control services. We consider that the formula gives effect to the revenue cap.
5. (1)  i=1,...,n and j=1,...,m and t=1,...,5
6. (2)  t = 1,2,…,5
7. where;
8. (3)  t = 1
9. (4)  t = 2,3,4,5
10. Where:
11.  is the maximum allowable revenue in year t.
12.  is the price of component i of tariff j in year t.
13.  is the forecast quantity of component i of tariff j in year t.
14.  is the annual smoothed revenue requirement in the Post Tax Revenue Model for year t. Adjusted as necessary to account for any difference between actual inflation and estimated inflation.
15.  is the adjusted annual smoothed revenue requirement for year t.
16.  is the sum of incentive scheme adjustments in year t. To be decided in the final decision.
17.  is the sum of end-of-period adjustments in year t. Likely to incorporate but not limited to adjustments from the initial regulatory control period. To be decided in the final decision.
18.  is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the overs and unders account. To be decided in the final decision.
19.  is the percentage increase in the consumer price index. To be decided in the final decision.
20.  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 final decision.
21.  is the sum of the s-factors for all parameters after application of the s-bank adjusted for the change in the annual revenue requirement between the last year of the 2011-2015 regulatory control period to 2016.
22.  is the s-factor for regulatory year t.

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

1. We will apply a revenue cap to the type 5 and 6 and smart metering service - not subject to competition. We will apply caps on the prices of individual services in the next regulatory control period to alternative control services. Our approach is supported by the five Victorian electricity distributors.[[209]](#footnote-209) We have classified the following services as alternative control services:

* type 5, 6 and smart metering services - regulated service
* ancillary network services
* shared public lighting assets

Our main consideration is that the benefit of caps on the prices of individual services is providing cost reflective pricing. We consider this benefit outweighs any detriment from increased administrative costs.

Through the distribution determination process, we will confirm the basis of the control mechanism for alternative control services.[[210]](#footnote-210) That is, we will confirm whether we will set prices using a building block approach or another method. Prices for certain ancillary network services will be determined on a quoted basis. The five Victorian electricity distributors will propose the approach to determining quoted prices, which we will consider in making our distribution determination. Typically, 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 distributors may only be able to quote on the service once they know the scope of the work.

Our consideration of the relevant factors is set out below.

### Influence on the potential to develop competition

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

### Administrative costs

Our view is that there will be no material impact on administrative costs for ancillary network services, connection services and public lighting services because we are continuing with caps on prices of individual services.

We consider the classification of services and the basis of the form of control mechanism are the primary influences on administrative costs. We recognise the proposed change in classification of type 5 and 6 and smart metering services and thus, a change in control mechanism, may result in some additional administrative costs. We consider these costs will largely be incurred in the transitioning to the new control mechanism. We consider the changes will be the minimum necessary to transition from regulation under the Victorian AMI CROIC to chapter 6 of the NER. We consider these benefits warrant a short term increase in administrative costs.

### Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. Our consideration of other factors in clause 6.2.5(d) of the rules leads us to the conclusion that the continuation of the current control formula of a cap on the price of individual services would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.

Metering services and ancillary network services

1. As we propose reclassifying these services a change in regulatory arrangements will be made regardless of the control mechanism we determine.

Public lighting

Our decision to apply caps on the prices of individual services is consistent with the current regulatory arrangements in Victoria.

### Desirability of consistency between regulatory arrangements

1. We consider consistency across jurisdictions is generally desirable but is not primary to our consideration in this instance. Desirability needs to be weighed against the other factors under clause 6.2.5(c) of the rules. The outcomes under the factors reveal outcomes that further the national electricity objectives and are consistent with the revenue and pricing principles.

### Cost reflective prices

1. We consider that caps on the prices of individual services are more suitable than other control mechanisms for delivering cost reflective prices. Under caps on the prices of individual services, we will estimate the cost of providing each service and set the price at that cost. If competition develops within the period on some or all services, distributors will be able to compete by charging below the cap. However, unlike under a WAPC, distributors will not be able to compensate for such reductions by increasing the price on non-competitive services. This will enhance cost reflective prices for both competitive and non-competitive services.

### Formulae for alternative control services

1. We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for alternative control services in this F&A paper.[[211]](#footnote-211) We must include the formulae as set out below in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[[212]](#footnote-212) In their submission the SLG objected to this formula.[[213]](#footnote-213) Although the public lighting service is subject to an alternative control classification the control mechanism is implemented through a public lighting model under a building block approach. We consider the matters SLG have raised can be considered in revising the public lighting model and through tariff reform. This revision will be undertaken in conjunction with the determination process. We also expect the next determination will be subject to new tariff reforms proposed by the AEMC.[[214]](#footnote-214)

Services currently classified as alternative control services and remain classified as alternative control services

1. Below is a formulae to apply to alternative control services, which we propose to remain classified as alternative control services. We consider that the formula gives effect to the cap on the prices of individual services:[[215]](#footnote-215)
2.  i=1,...,n and t=1,2,3,4
3. 
4. Where:
5. is the cap on the price of service i in year t
6. is the price of service i in year t. The initial value is to be decided in the final decision.
7. is the percentage increase in the consumer price index. To be decided in the final decision.
8. is the X-factor for service i in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the final decision.

Type 5, 6 and smart metering - regulated service

1. Below is a proposed formula to apply to the type 5, 6 and smart metering - regulated service. We consider that the formula gives effect to the revenue cap.
2. (1)  i=1,...,n and j=1,...,m and t=1,...,5
3. (2) 
4. (3) 
5. Where:
6.  is the maximum allowable revenue in year t.
7.  is the price of component i of tariff j in year t.
8.  is the forecast quantity of component i of tariff j in year t.
9.  is the annual revenue requirement for year t.
10.  in 2016 is the annual smoothed revenue requirement in the Post Tax Revenue Model for the 2016 year in 2015 dollar value. After 2016 this is the ARt from the previous year.
11.  is the adjustments in year t for true-ups relating to the AMI-OIC.
12.  is the sum of annual adjustment factors in year t for the overs and unders account.

 is the percentage increase in the consumer price index. To be decided in the final decision.

1.  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 decision.

# AER-final-orangeIncentive schemes

1. This attachment sets out our proposed approach to the application of a range of incentive schemes to the five Victorian electricity distributors for the next regulatory control period. At a high level, our proposed approach is to apply the:

* service target performance incentive scheme with a financial penalty or reward of nominally ±5 per cent revenue at risk[[216]](#footnote-216)
* new efficiency benefit sharing scheme
* capital expenditure sharing scheme
* demand management incentive scheme including a demand management innovation allowance.

## Service target performance incentive scheme

1. This section sets out our proposed approach and reasons for applying the service target performance incentive scheme (STPIS) to the five Victorian electricity distributors in the next regulatory control period.
2. Our national distribution STPIS[[217]](#footnote-217) provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to safeguard that cost efficiencies encouraged under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).
3. 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[[218]](#footnote-218) experiencing service below a predetermined level.[[219]](#footnote-219)

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

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

1. Distributors can propose to vary the application of the STPIS in their regulatory proposal.[[220]](#footnote-220) We can accept or reject the proposed variation in our determination. Each applicable year we will calculate a distributor's s-factor based on its service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to reduce price volatility for customers.[[221]](#footnote-221) A distributor proposing a delay must provide in writing its reasons and justification for considering that the delay will result in reduced price variations to customers.
2. Our national STPIS currently applies to the five Victorian electricity distributors. The five Victorian electricity distributors are currently subject to financial penalty or reward ranging between ±5 per cent (CitiPower, Powercor, Jemena, United Energy) and ±7 per cent (AusNet Services) through an s-factor adjustment to revenue. The GSLs are a jurisdictional requirement, so the GSL component of the STPIS will not apply.

### AER's proposed approach

Our proposed approach is to continue to apply the national STPIS to the five Victorian electricity distributors in the next regulatory control period. United Energy generally supported this position.[[222]](#footnote-222) Our proposed approach to applying the national STPIS in the next regulatory control period will be to:

* set revenue at risk for each distributor within the range nominally, ±5 per cent[[223]](#footnote-223)
* segment the network according to feeder categories (CBD, urban, short rural and long rural as appropriate for each distributor) in the Victorian jurisdictional distribution licence conditions
* set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index or SAIFI) and customer service (telephone answering) parameters
* set performance targets based on the distributors' average performance over the past five regulatory years
* apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance targets[[224]](#footnote-224)
* apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates to past investments
* apply the methodology as indicated in our national STPIS to the calculation of incentive rates to new investments and, if practicable, amend the value of customer reliability (VCR) values applicable to future investments consistent with values determined from the most recent AEMO review of VCR values..

1. We will not apply the GSL component as the five Victorian electricity distributors are subject to a jurisdictional GSL scheme.[[225]](#footnote-225) DSDBI supported the continuation of this approach.[[226]](#footnote-226)
2. We are aware of policy reviews indicating the need to reform the STPIS. The AEMC recently conducted a review of distribution reliability frameworks in the NEM.[[227]](#footnote-227) The Australian Energy Market Operator (AEMO) has published its analysis on how willing consumers are to pay for improvements in network reliability.[[228]](#footnote-228) We consider there is likely to be inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for the five Victorian electricity distributors. We will, however, seek to incorporate values for VCR derived from the AEMO study in the determination for future application of the scheme.

### AER's assessment approach

1. The rules require us to have regard to several factors in developing and implementing a STPIS for the five Victorian electricity distributors.[[229]](#footnote-229) These include:

* Jurisdictional obligations
* consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
* checking that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation any regulatory obligations or requirements to which the distributor is subject.
* Benefits to consumers
* 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 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 rules or the relevant distribution determination
* the need to provide incentives that are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
* the possible effects of the schemes on incentives for the implementation of non-network alternatives.

Our approach and reasons for developing the STPS are contained in our final decision for the national distribution STPIS.[[230]](#footnote-230)

### Reasons for AER's proposed approach

1. Our reasons for proposing to apply the STPIS to the five Victorian electricity distributors in the next regulatory control period are set out below.

Jurisdictional obligations

In Victoria, the Essential Services Commission (ESCV) administers and monitors compliance with the distribution licence conditions set out in the Electricity Distribution Code. As required by the rules, we will consult with the ESCV and the DSDBI, as jurisdictional authorities, on the implementation of the STPIS[[231]](#footnote-231) before finalising our distribution determination.

Our proposed approach to applying the STPIS in Victoria does not intend to compromise the distributors' ability to comply with jurisdictional licence obligations or create duplication. We intend doing this by not:

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

Benefits to consumers

1. We are mindful of the potential impact of the STPIS on consumers. Under the rules, 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.[[232]](#footnote-232)
2. Under the STPIS, the distributors' financial penalty or reward in each year of the regulatory control period is the change in its annual revenue allowance after the s-factor adjustment. Economic analysis of the value consumers place on improved service performance is an important input to the administration of the scheme. Value of customer reliability (VCR) studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of energy during a supply interruption. As outlined in our national STPIS, we will use VCR estimates at different stages of our annual s-factor calculation to:

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

The VCR estimates in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.[[233]](#footnote-233) The distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.[[234]](#footnote-234) The AEMC conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.[[235]](#footnote-235) AEMO has recently published new estimates of VCR.[[236]](#footnote-236)

1. United Energy and AusNet Services both submitted that in view of changed circumstances, a review of the national STPIS should be undertaken before, or in conjunction with, the next distribution determination.[[237]](#footnote-237) We think it is in the best interests of all parties that an updated VCR be used. This is because it will provide confidence that the true value that customers place on reliability is reflected. Accordingly, we expect to undertake a review of our national STPIS now these studies are complete. However, any change to the STPIS is subject to the distribution consultation procedures in the rules.[[238]](#footnote-238) We consider there is insufficient time to conduct a comprehensive review of the STPIS before the five Victorian electricity distributors submit proposals in April 2015 for the next regulatory control period. Therefore our position is to apply the national STPIS in its current form but apply revised values for VCR through the distribution determination. In doing so we will need to consider whether a change in VCR values results in any transitional issues which must be addressed through the STPIS or through the determination. In particular, whether the changed values of VCR should be applied to all investments or only to new investments. If feasible, we will consider conducting a more thorough review of the STPIS as a parallel process to the determination. We will consider this issue at that time and consult with the five Victorian electricity distributors.

Balanced incentives

1. 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 note that United Energy sought a variation to the weighting of the parameters that should apply to them.[[239]](#footnote-239) We consider this issue should be resolved through the determination process when detailed information as to the impact of the variation can be better assessed, rather than at this early stage.

Distributor incentives under the STPIS

1. How we measure actual service performance and set performance targets can significantly impact how well the STPIS meets its stated objectives.
2. The rules require us to consider past performance of the distributor's network in developing and implementing the STPIS.[[240]](#footnote-240) Accurately setting the starting point for an incentive scheme was also noted as important by the CCP.[[241]](#footnote-241) Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.[[242]](#footnote-242) Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits the distributors' incentive to underperform in the final year of a regulatory control period to make future targets less onerous.
3. Our national STPIS limits variability in penalties and rewards caused by circumstances outside the distributors' 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.
4. Our national STPIS recognises differences across and within distribution networks. Measured performance and performance targets are specific to each segment of a distributor's network.

Interactions with our other incentive schemes

1. In applying the STPIS we must consider any other incentives available to the distributor under the rules or relevant distribution determination.[[243]](#footnote-243) In Victoria, the STPIS will interact with our expenditure and demand management incentive schemes.
2. The efficiency benefit sharing scheme (EBSS) provides distributors with an incentive to reduce operating costs. The STPIS counterbalances this incentive by discouraging cost efficiencies arising through reduced service performance for customers. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets. In accordance with the rules we must set incentive rates to offset any financial incentives the distributors may have to reduce costs at the expense of service levels. [[244]](#footnote-244)
3. In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[[245]](#footnote-245)
4. The capital expenditure sharing scheme (CESS) rewards distributors 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.
5. The rules require us to consider the possible effects of the STPIS on the distributors' incentives to implement non-network alternatives to augmentation. The STPIS treats the reliability implications of network and non-network solutions symmetrically, neither encouraging nor discouraging non-network alternatives to augmentation. The interaction of the schemes is an important factor. That is, the STPIS provides an incentive for distributors to maintain network performance balanced against incentives that encourage them to defer or avoid network investment.

We are aware of the perceived disincentive to implement demand-side alternatives to network augmentation created by reliability performance measures in the STPIS. Higher risk of failure to meet STPIS performance targets may act as a disincentive for non-network alternatives to network investment. One way to address this would be to exclude outages caused by non-network solutions from the calculation of actual performance. However, since network planning decisions are within the distributors' control, we consider this to be unnecessary.

## Efficiency benefit sharing scheme

1. The efficiency benefit sharing scheme (EBSS) is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices. This section sets out our proposed approach and reasons on how we intend to apply the EBSS to the five Victorian electricity distributors in the next regulatory control period.

### ­AER's proposed approach

1. We propose applying our new EBSS[[246]](#footnote-246) to the five Victorian electricity distributors for the 2016–20 regulatory control period.
2. AusNet Services, CitiPower, Jemena, Powercor and United Energy have noted our intention to apply the scheme.[[247]](#footnote-247) Our distribution determination for the five Victorian electricity distributors for the next regulatory control period will specify how we will apply the EBSS.

### AER's assessment approach

The EBSS must provide for a fair sharing between distributors and consumers of opex efficiency gains and efficiency losses.[[248]](#footnote-248) We must also have regard to the following factors in developing and implementing the EBSS:[[249]](#footnote-249)

* 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.

### Reasons for AER's proposed approach

1. The current EBSS applies to five Victorian electricity distributors in their current regulatory control period.[[250]](#footnote-250) As part of our Better Regulation program we consulted on and published the new EBSS, taking into account the requirements of the rules.
2. The new EBSS retains the same form as the current EBSS, and merges the distribution and transmission schemes. Changes in the new EBSS relate to the criteria for adjustments and exclusions under the scheme.[[251]](#footnote-251) We also amended the scheme to provide flexibility to account for any adjustments made to base year opex to remove the impacts of one-off factors. The new EBSS also clarifies how we will determine the carryover period. These revisions affect how carryover amounts are calculated for future regulatory control periods.[[252]](#footnote-252)
3. In this section we set out why we propose to apply the new EBSS to the five Victorian electricity distributors in the next regulatory control period.
4. In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.[[253]](#footnote-253) This reasoning extends to the factors we must have regard to in implementing the scheme.
5. The EBSS must provide for a fair sharing of efficiency gains and losses.[[254]](#footnote-254) Under the scheme distributors and consumers receive a benefit where a distributor reduces its costs during a regulatory control period and both bear some of any increase in costs.
6. Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.[[255]](#footnote-255) The EBSS provides a continuous incentive for distributors to achieve opex efficiencies throughout the subsequent period. This is because the distributor receives carryover payments so it retains any efficiency gains or losses it makes within the regulatory period for the length of the carryover period. This is regardless of the year in which it makes the gain or loss.[[256]](#footnote-256)
7. This continuous incentive to improve efficiency encourages efficient and timely opex throughout the regulatory control period, and reduces the incentive for a distributor to inflate opex in the expected base year. This provides an incentive for distributors to reveal their efficient opex which, in turn, allows us to better determine efficient opex forecasts for future regulatory control periods.
8. The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.[[257]](#footnote-257) For instance, the combined effect of our forecasting approach and the EBSS is that opex efficiency gains or losses are shared approximately 30:70 between distributors and consumers. This means for a one dollar efficiency saving in opex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.
9. Example 1 shows how the EBSS operates. It illustrates how the benefits of a permanent efficiency improvement are shared approximately 30:70 between a network service provider and consumers.

Example : How the EBSS operates

1. Assume that in the first regulatory period, a distributor's forecast opex is $100 million per annum (p.a.).
2. Assume that during this period the distributor delivers opex equal to the forecast for the first three years. Then, in the fourth year of the regulatory period, the distributor implements a more efficient business practice for maintaining its assets. As a result, the distributor will be able to deliver opex at $95 million p.a. for the foreseeable future.
3. This efficiency improvement affects regulated revenues in two ways:
   1. Through forecast opex. If we use the penultimate year of the regulatory period to forecast opex in the second regulatory period, the new forecast will be $95 million p.a. If the efficiency improvement is permanent, all else being equal, forecast opex will also be expected to be $95 million p.a. in future regulatory periods.
   2. Through EBSS carryover amounts. The distributor receives additional carryover amounts so that it receives exactly six years of benefits from an efficiency improvement. Because the distributor has made an efficiency improvement of $5 million p.a. in Year 4, to ensure it receives exactly six years of benefits, it will receive annual EBSS carryover amounts of $5 million in the first four years (Years 6 to 9) of the second regulatory period.
4. As a result of these effects, the distributor will benefit from the efficiency improvement in Years 4 to 9. This is because the annual amount the distributor receives through the forecast opex and EBSS building blocks ($100 million) is more than what it pays for opex ($95 million) in each of these years.
5. Consumers benefit from Year 10 onwards after the EBSS carryover period has expired. This is because what consumers pay through the forecast opex and EBSS building blocks ($95 million) is lower from Year 10 onwards.
6. Table 9 (below) provides a more detailed illustration of how the benefits are shared between distributors and consumers over time.

(Example 1 continued)

Table 9: Example of how the EBSS operates

|  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | Regulatory period 1 | | | | | Regulatory period 2 | | | | | Future |
| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |
| Forecast (Ft) | 100 | 100 | 100 | 100 | 100 | 95 | 95 | 95 | 95 | 95 | 95 p.a. |
| Actual (At) | 100 | 100 | 100 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 p.a. |
| Underspend (Ft – At = Ut) | 0 | 0 | 0 | 5 | 5 | 0 | 0 | 0 | 0 | 0 | 0 p.a. |
| Incremental efficiency gain (It = Ut – Ut–1) | 0 | 0 | 0 | 5 | 0 | 0\* | 0 | 0 | 0 | 0 | 0 p.a. |
|  |  |  |  |  |  |  |  |  |  |  |  |
| Carryover (I1) |  | 0 | 0 | 0 | 0 | 0 |  |  |  |  |  |
| Carryover (I2) |  |  | 0 | 0 | 0 | 0 | 0 |  |  |  |  |
| Carryover (I3) |  |  |  | 0 | 0 | 0 | 0 | 0 |  |  |  |
| Carryover (I4) |  |  |  |  | 5 | 5 | 5 | 5 | 5 |  |  |
| Carryover (I5) |  |  |  |  |  | 0 | 0 | 0 | 0 | 0 |  |
| Carryover amount (Ct) |  |  |  |  |  | 5 | 5 | 5 | 5 | 0 | 0 p.a. |
| Benefits to distributor (Ft – At +Ct) | 0 | 0 | 0 | 5 | 5 | 5 | 5 | 5 | 5 | 0 | 0 p.a. |
| Benefits to consumers (F1 – (Ft +Ct)) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 5 p.a. |
| Discounted benefits to distributor\*\* | 0 | 0 | 0 | 5 | 4.7 | 4.5 | 4.2 | 4.0 | 3.7 | 0 | 0 |
| Discounted benefits to consumers\*\* | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3.5 | 58.8\*\*\* |

Notes: \* At the time of forecasting opex for the second regulatory period we do not know actual opex for year 5. Consequently this is not reflected in forecast opex for the second period. That means an underspend in year 6 will reflect any efficiency gains made in both year 5 and year 6. To ensure the carryover rewards for year 6 only reflect incremental efficiency gains for that year we subtract the incremental efficiency gain in year 5 from the total underspend. In the example above, I6 = U6 – (U5 – U4).

\*\* Assumes a real discount rate of 6 per cent.

\*\*\* As a result of the efficiency improvement, forecast opex is $5 million p.a. lower in nominal terms. The estimate of $58.7m is the net present value of $5 million p.a. delivered to consumers annually from year 11 onwards.

Table 10 sums the discounted benefits to distributors and consumers from the bottom two rows of Table 9. As illustrated below, the benefits of the efficiency improvement are shared approximately 30:70 in perpetuity between the distributor and consumers.

Table 10: Sharing of efficiency gains—Year 4 forecasting approach, with EBSS

|  |  |  |
| --- | --- | --- |
|  | NPV of benefits of efficiency improvement | Percentage of total benefits |
| Benefits to distributor | $26.1 million | 30 per cent |
| Benefits to consumers | $62.3 million | 70 per cent |
| Total | $88.3 million | 100 per cent |

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.[[258]](#footnote-258) Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice versa. The CESS is a symmetric capex scheme with a 30 per cent incentive power. This is consistent with the incentive power for opex when we use an unadjusted base year approach in combination with an EBSS. When the CESS and EBSS are applied, incentives will be relatively balanced, and distributors should not have an incentive to favour opex over capex or vice versa. We discuss the CESS further in section 3.3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives:[[259]](#footnote-259)

* Expenditure on non-network alternatives generally takes the form of opex rather than capex. Successful non-network alternatives should result in the distributor spending less on capex than it otherwise would have. Non-network alternatives and demand management incentives are discussed further in section 3.4
* When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor will receive a net reward for implementing the non-network alternative.[[260]](#footnote-260) This is because the rewards and penalties under the EBSS and CESS are balanced and symmetric. In the past where the EBSS operated without a CESS, we excluded expenditure on non-network alternatives when calculating rewards and penalties under the scheme. This was because distributors may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.[[261]](#footnote-261)

Incentives for opex and capex are balanced (30 per cent) and constant. They are also balanced with the incentives under our STPIS. This encourages businesses to make efficient decisions on when and what type of expenditure to incur, in order to meet service reliability targets.

The ex post review complements the CESS to provide distributors with an additional incentive to help ensure that any overspends are efficient and prudent. Under the CESS a business bears 30 per cent of the overspend. However, if the overspend is found to be inefficient, the ex post reviews mean the business could bear 100 per cent of the inefficient overspend.[[262]](#footnote-262)

## Capital expenditure sharing scheme

1. The CESS provides financial rewards for distributors whose capex becomes more efficient and imposes financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. This section sets out our proposed approach and reasons for how we intend to apply the CESS to the five Victorian electricity distributors in the next regulatory control period.
2. The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between distributors and network users.
3. The CESS works as follows:

* We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
* We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the distributor's share of the underspend or overspend should be.
* We calculate the CESS payments taking into account the financing benefit or cost to the distributor of the underspends or overspends.[[263]](#footnote-263) We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
* The CESS payments will be added or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

1. Under the CESS a distributor retains 30 per cent of an underspend or overspend, while consumers retain 70 per cent of the underspend or overspend. This means that for a one dollar saving in capex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

### AER's proposed approach

1. We propose to apply the CESS, as set out in our capex incentives guideline,[[264]](#footnote-264) to the five Victorian electricity distributors in the next regulatory control period.

### AER's assessment approach

1. In deciding whether to apply the CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:[[265]](#footnote-265)

* make that decision in a manner that contributes to the capex incentive objective[[266]](#footnote-266)
* consider the CESS principles,[[267]](#footnote-267) capex objectives,[[268]](#footnote-268) other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

1. 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.

### Reasons for AER's proposed approach

1. Our proposed approach is to apply the CESS to the five Victorian electricity distributors in the next regulatory control period as we consider this will contribute to the capex incentive objective. Ultimately, the aim is that consumers pay only for efficient and prudent capex undertaken by distributors. That is, our capex incentive measures mean that consumers pay only a portion of efficient overspends, pay nothing for inefficient overspends and consumers share in the benefits when a distributor is able to spend less than its forecast capex allowance. The CCP supported our preliminary position. [[269]](#footnote-269) However, DSDBI expressed reservation that customers may not benefit from the application of the CESS, on the basis that the reasons for variation in capital expenditure are difficult to identify and deferral of capital between periods can mask the true measure of capital expenditure.[[270]](#footnote-270)
2. The five Victorian electricity distributors are not 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.[[271]](#footnote-271) The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[[272]](#footnote-272) We are also proposing to apply forecast depreciation, which we discuss further in attachment 5.
3. In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the EBSS, STPIS, and DMIS—which we propose the five Victorian electricity distributors will be subject to in the next regulatory control period.
4. For capex, the sharing of underspends and overspends happens at the end of each regulatory period when we update a distributor's RAB to include new capex. If a distributor spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the business had spent the full amount of the capex forecast. This leads to lower prices in the future.
5. Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.[[273]](#footnote-273) Because of this a distributor may choose to spend capex earlier, or on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.
6. With the CESS a distributor faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide distributors with an ex ante incentive to spend only efficient capex. Distributors that make efficiency gains will be rewarded through the CESS. Conversely, distributors that make efficiency losses will be penalised through the CESS. In this way, distributors will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more likely to reflect the capex criteria. In particular, if a distributor is subject to the CESS, its capex is more likely to be efficient and to reflect the costs of a prudent distributor.

Historically, we were required to add all capex to a distributor's RAB regardless of whether it was efficient, or exceeded the approved forecast. This meant consumers were paying prices that reflected all of a distributor’s capex which may have included inefficient capex. However, in addition to the ex post measures discussed at section 3.2 above, we now have the ability to exclude inefficient related party margins and capitalised opex that does not benefit consumers. Overall, the CESS will provide distributors with clear incentives to pursue efficiency gains throughout the full regulatory control period.[[274]](#footnote-274)

When the CESS, EBSS and STPIS apply to distributors, incentives for opex, capex and service are balanced. They give distributors an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced (30 per cent) and constant. They are also balanced with the incentives under our STPIS. This encourages distributors to make efficient decisions on when and what type of expenditure to incur, in order to meet service reliability targets.

## Demand management incentive scheme

1. This section sets out our proposed approach and reasons for applying a demand management incentive scheme (DMIS) to the five Victorian electricity distributors in the next regulatory control period.[[275]](#footnote-275)

The usage patterns of geographically dispersed consumers determine how electrical power flows through a distribution network. Since consumers use energy in different ways, different network elements reach maximum utilisation levels at different times. Distributors have historically planned their network investment to provide sufficient capacity for these situations. As peak demand periods are typically brief and infrequent, network infrastructure often operates with significant redundant capacity.

This underutilisation means that augmentation of network capacity may not always be the most efficient means of catering for increasing peak demand. Demand management refers to any effort by a distributor to lower or shift the demand for standard control services.[[276]](#footnote-276) Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

1. The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.[[277]](#footnote-277) To meet this requirement, and motivated by the need to improve the five Victorian electricity distributors' capability in the demand management area, we implemented a DMIS in our distribution determinations for the current regulatory period.
2. The current DMIS includes two components:

* Part A provides for an innovation allowance (DMIA) to be incorporated into each distributor's revenue allowance for each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA in the previous year, which we then assess against specific criteria.
* Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A for distributors under a weighted average price cap. In the current regulatory control period, the five Victorian electricity distributors are subject to a WAPC form of control. As a revenue cap is to apply in the next regulatory control period, Part B will not be relevant to the five Victorian electricity distributors.

1. Currently both Part A and Part B of the scheme applies to the five Victorian electricity distributors.

### AER's proposed approach

1. Our proposed approach, supported by the Victorian distributors,[[278]](#footnote-278) is to continue applying the DMIS in the next regulatory control period.
2. We acknowledge the need to reform the existing demand management incentive arrangements in Victoria. The COAG Energy Council (formerly SCER) is currently considering a series of rule changes[[279]](#footnote-279) proposed by the AEMC in its Power of Choice review[[280]](#footnote-280) examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. We may develop and implement a new DMIS during the next regulatory control period, depending on the progress of the rule change process. For these reasons, we propose to allow a DMIA. We will set the quantum of this allowance in the determination. The Victorian distributors sought the continuation of this allowance.[[281]](#footnote-281)
3. Under the Power of Choice review it is possible that a new DMIS will be applied within the next regulatory control period. The F&A is only intended to provide an outline of our proposed approach and is not binding.[[282]](#footnote-282) It is our intention to have a demand management scheme and we would want to adopt a revised scheme, subject to the requirements of the rules, which may include transitional provisions requiring or allowing us to apply a new scheme or some variations within period.

### AER's assessment approach

1. The rules require us to have regard to several factors in developing and implementing a DMIS for the Victorian distributors.[[283]](#footnote-283) These are:

* Benefits to consumers
* benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
* the willingness of customers to pay for increases in costs resulting from implementing a DMIS.
* Balanced incentives
* the effect of a particular control mechanism (that is, price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
* the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
* the extent the distributor is able to offer efficient pricing structures
* the possible interactions between a DMIS and the other incentive schemes.

### Reasons for AER's proposed approach

1. This section outlines the reasons for our proposed approach to apply the DMIS to Five Victorian electricity distributors in the next regulatory control period.

Benefits to consumers

1. Customers ultimately fund the DMIA adjustment to a distributor's annual revenue each year. As such, we are mindful of the potential impact of the DMIS on consumers. Under the rules, we must consider customers' willingness to pay for any higher costs resulting from the scheme so benefits to consumers are sufficient to warrant any penalty or reward.[[284]](#footnote-284)
2. We assess projects for which distributor's apply for DMIA funding under a specific set of criteria. The DMIA aims to enhance distributors' knowledge and experience with non-network alternatives, therefore improving the consideration of demand management in future decision making. This means the benefits of any higher consumer prices directly caused by the scheme may not be revealed until later periods. Benefits include more efficient utilisation of existing network infrastructure and the deferral of network augmentation expenditure.
3. We expect the potential long-term efficiency gains resulting from improved distributor capability to undertake demand management initiatives to outweigh short-term price increases. Price impacts will be minimal as adjustments to annual revenue under the DMIA are capped at modest levels and allowances are provided on a 'use it or lose it' basis.
4. While studies[[285]](#footnote-285) to date indicate that customers are supportive of demand management initiatives in principle, we know little about their willingness to pay. We consider our proposed application of the DMIS to be suitable in light of this limited information, given that the modest level of the DMIA means potential price increases will be minimal.

Balanced incentives

1. We administer our incentive schemes within a regulatory control period to align distributor incentives with the National Electricity Objective. In implementing the DMIS, we need to be aware of how the scheme interacts within a distributor's overall incentive environment.

Control mechanism and service classification

1. The rules require us to have regard for how a distributor's control mechanism influences its incentives to adopt or implement efficient non-network alternatives to network augmentation.[[286]](#footnote-286) We consider that a revenue cap form of control does not provide a disincentive for the five Victorian electricity distributors to reduce the quantity of electricity as approved regulated revenues are not dependent on the quantity of electricity sold. That is, under a form of control where revenue is at least partially dependent on the quantity of electricity sold (for example, a price cap), a successful demand management program that causes a reduction in demand may result in less revenue for a distributor. A revenue cap avoids this scenario.
2. We are also required to consider the effect of service classification on a distributor's incentive to adopt or implement efficient embedded generator connections.[[287]](#footnote-287) We consider our proposed application of the DMIS meets this requirement as the Victorian distributors will be under a revenue cap in the next regulatory control period.

Distributor's ability to offer efficient pricing structures

1. The rules also require us to consider the extent to which the distributor is able to offer efficient pricing structures in our design and implementation of a DMIS.[[288]](#footnote-288) Efficient pricing structures reflect the true costs of supplying electricity at a particular part of the network at any given time. These tariff structures would price electricity highest during peak demand periods, reflecting the high costs of transporting energy when network utilisation is at its highest. This price signal would discourage grid electricity usage at these times, lowering peak demand and adjusting network utilisation downwards.
2. Victoria has a very high penetration of the required metering and other enabling technologies, which will enable the introduction of more efficient tariffs. At present, the Victorian distributors' ability to adopt more efficient price signals is constrained only by the need to carefully consider the best approach to implementing efficient tariffs in consultation with their customers and electricity retailers. We consider that moves to efficient pricing, enabled by 'smarter' grid technologies will have a significant impact on distribution network utilisation in the future. Additionally, retail pricing tariffs have not in the past mirrored the cost reflective distribution tariffs approved by us. While these pending reforms to retail tariffs remain in the early stages of implementation, the DMIA incentivises distributors to trial measures that will assist the transition of networks to more efficient pricing.

Interaction with our other incentive schemes

The DMIA intends to encourage businesses to investigate and implement innovative demand management strategies, regardless of their potential efficiency. In developing and implementing the DMIS in Vic, we must consider how it could potentially interact with our other incentive schemes.[[289]](#footnote-289) Neither our expenditure incentive schemes (EBSS and CESS) nor STPIS intend to discourage a distributor from using its DMIA.

While a distributor's annual opex allowance incorporates the DMIA, we may exclude the DMIA from the EBSS.[[290]](#footnote-290) Any potential substitution between opex and capex resulting from projects approved under the DMIA will be incentive-neutral as our proposed EBSS and CESS provide balanced incentives for opex and capex savings.

# AER-final-orangeExpenditure forecast assessment guideline

1. This attachment sets out our intention to apply our expenditure forecast assessment guideline (guideline)[[291]](#footnote-291) including the information requirements to the five Victorian electricity distributors for the 2016–20 regulatory control period. We propose applying the guideline as it sets out our new expenditure assessment approach developed and consulted upon during the Better Regulation program. The guideline outlines for distributors and interested stakeholders the types of assessments we will do to determine efficient expenditure allowances, and the information we require from the distributors to do so.

We were required to develop the guideline under the rules.[[292]](#footnote-292) The guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. In the F&A we must set out our proposed approach to the application of the guideline.[[293]](#footnote-293)

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

* models for assessing proposed replacement and augmentation capex
* benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
* methodology, governance and policy reviews
* predictive modelling and trend analysis
* cost benefit analysis and detailed project reviews.[[294]](#footnote-294)

We developed the guideline to apply broadly to all electricity transmission and distribution businesses. However, some customisation of the data requirements contained in the guideline might be required. This is particularly in regard to services that we classify in different ways and are subject to different forms of control. For example, nationally consistent data for benchmarking and trend assessment of public lighting costs may not by themselves be sufficient to assess the particular pricing models employed by particular distributors. The guideline itself does not explicitly require these distributors to submit or justify inputs to these models and we may request specific data to assist us with this analysis. We expect that these data customisation issues would be addressed through the Regulatory Information Notice that we will issue to the five Victorian electricity distributors for the next regulatory control period.

Jemena sought greater detail of which elements of our assessment tools the AER would apply to specific aspects of their regulatory proposals.[[295]](#footnote-295) The AER reserves the right to apply any, or all, of the tools and techniques at its disposal to assess an individual proposal. In doing so, our intention is to be efficient. It is likely that we will selectively apply tools that best match the specific circumstances of a particular proposal. The degree to which a given tool or technique is relevant will also depend on how a particular cost measures up when overall benchmarks are considered. It may be apparent from a consideration of benchmarks that a particular proposal should attract either more, or less scrutiny. The judicious application of the assessment tools appropriate to a particular expenditure may indicate a particular category of capital or operating expenditure requires a greater, or lesser, degree of scrutiny. The AER cannot predict these possibilities in the absence of a specific proposal. Therefore, we may apply any or all of the tools to a particular proposal.

# AER-final-orangeDepreciation

1. Capital expenditure (capex) refers to expenditure on assets that are long lived. Distributors therefore recover the costs over the life of the asset rather than when the costs are incurred. This return of capital is also called depreciation. The alternative is to compensate distributors for costs entirely in the year they are incurred. This is the approach we use for operating expenses.
2. The distributors are provided an allowance for depreciation that is calculated on the existing regulatory asset base (RAB) and forecast additions or capex to the RAB. The proportion of depreciation related to forecast capex, like all forecasts, is subject to forecasting error. Once actual capex is known, it is possible to accurately determine what the depreciation allowance would have been. The issue under consideration in this attachment is whether the approach for depreciation in the RAB roll forward should employ the allowance based on forecast capex (forecast depreciation) or actual capex (actual depreciation) over the regulatory control period.
3. This attachment sets out our proposed approach to use forecast depreciation when rolling forward to establish the RAB at the commencement of the 2021–25 regulatory control period.
4. Once a distributor's capex allowance is determined, the funding for the approved capex program will be returned to the distributor for each year of the upcoming regulatory control period through the sum of:

* the forecast RAB multiplied by the weighted average cost of capital (WACC);[[296]](#footnote-296) and
* depreciation.[[297]](#footnote-297)

1. As the capex allowance is set before the regulatory control period commences, a distributor has an incentive to spend less than the allowance and through these savings earn higher profits. Hence a distributor can 'keep the difference' between the allowance and what it cost to finance the actual capex until the end of the regulatory control period. Conversely, if a distributor spends more than its allowance, its revenue will not cover the overspend meaning that the distributor has to bear the cost of financing the overspend within the regulatory control period.[[298]](#footnote-298)
2. The depreciation we use to roll forward the RAB at the end of the current regulatory control period 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.

1. The choice of depreciation approach is one part of the overall capex incentive framework. In particular, the difference between the two approaches is the relative strength of the additional incentive to over-forecast or to underspend capex. This arises during the RAB roll forward at the end of the regulatory control period. To roll forward the RAB, we:

* start with the opening RAB for the regulatory control period
* add actual net capex for each year to the RAB
* remove forecast or actual depreciation for each year from the RAB
* determine the closing RAB at the end of the regulatory control period.

1. Regardless of the depreciation approach, we always update the RAB to reflect actual (prudent) capex. Therefore, when applying different depreciation approaches in the roll forward process, the closing RAB will only vary due to differences in the depreciation removed from this process.
2. Under a forecast depreciation approach, a distributor's RAB reduces to reflect the depreciation forecast set at the beginning of the regulatory control period. Whereas under an actual depreciation approach, the distributor's RAB reduces to reflect the re-calculated depreciation amount linked to each year’s actual capex. Where actual capex differs from forecast, actual depreciation will be different to the depreciation forecast. Therefore, the two approaches result in different closing RABs at the end of the regulatory control period.
3. Through the different approaches to depreciation and other building blocks, the regulatory framework creates incentives for distributors to over forecast or to defer efficient expenditure. This can encourage distributors to pursue capex efficiency improvements that will ultimately benefit both the distributor and electricity consumers. The relative sharing ratio between the distributor and consumers will be determined by the year in which the capex overspend or underspend occurs, whether actual or forecast depreciation is used to roll forward the RAB, and the expected life of the asset.
4. Consumers benefit from improved efficiencies through lower regulated prices. Where a capital expenditure sharing scheme (CESS) is applied, the forecast depreciation approach 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.[[299]](#footnote-299) In summary:

* If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that when applying actual depreciation in the roll forward, the RAB will increase by a lesser amount than if forecast depreciation were used. Therefore, 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 when applying actual depreciation in the roll forward, the RAB will increase by a greater amount than if forecast depreciation were 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.

1. The strength of capex reduction incentive from using actual depreciation to roll forward the RAB also varies with the expected life of the asset. Using actual depreciation will provide a stronger incentive for shorter lived assets compared to longer lived assets. Forecast depreciation, on the other hand, leads to the same incentive for all assets.

## AER's proposed approach

1. Our proposed approach is to use forecast depreciation to establish the RAB at the commencement of the 2021–25 regulatory control period for the five Victorian electricity distributors. We consider this approach will provide sufficient incentives for the distributors to achieve capex efficiency gains over the 2016–20 regulatory control period.

## AER's assessment approach

1. We must decide at our determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.[[300]](#footnote-300)
2. We are required to set out in our capex incentive guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.[[301]](#footnote-301) Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective.[[302]](#footnote-302) We must also have regard to:[[303]](#footnote-303)

* the incentives the service provider has in relation to undertaking efficient capex, including as a result of the application of any incentive scheme or any other incentives under the rules
* substitution possibilities between assets with relatively short economic lives and assets with relatively long economic lives and the relative benefits of such asset types
* the extent to which capex incurred by the service provider has exceeded forecast capex, and the amount of that excess capex which is not efficient
* the Capital Expenditure Incentive Guideline
* the capital expenditure factors.

## Reasons for AER's proposed approach

1. Consistent with our capex incentive guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2020–25 regulatory control period.

We had regard to the relevant factors in the rules in developing the approach to choosing depreciation set out in our capex incentive guideline.[[304]](#footnote-304)

Our approach is to apply forecast depreciation except where:

* there is no CESS in place and therefore 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 more effective incentive.

1. In making our decision at the determination stage on whether to use actual depreciation in either of these circumstances we will consider:

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

We have chosen forecast depreciation as our default approach because, in combination with the CESS, a distributor will retain 30 per cent of an underspend or overspend, while consumers will retain 70 per cent of the underspend or overspend. This means that for a one dollar saving in capex a business gets 30 cents of the benefit while consumers get 70 cents of the benefit. For the reasons given in our capex incentive guideline, we consider this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.[[305]](#footnote-305) That is, the reward should not be so high that it incentivises inefficient capex deferral. This could result in consumers paying too much for the capex (since they might fund the same capex in multiple regulatory control periods). Alternatively, consumers could experience a decline in service levels. Also, the power of the incentive should be set so as to achieve balance between the incentives for capex, opex and service.

Five Victorian electricity distributors are not currently subject to a CESS but we propose to apply the CESS in the 2016–20 regulatory control period. That is, we propose a sharing ratio of 30 per cent to the total capex efficiency gain/loss under the CESS. We discuss this further in section 3.3. CitiPower/Powercor supported the use of forecast depreciation given our intention to apply the CESS in the next regulatory control period.[[306]](#footnote-306) Jemena and United Energy accepted our proposal to apply CESS in the next regulatory control period.[[307]](#footnote-307)

1. For the five Victorian electricity distributors, at this stage, 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.[[308]](#footnote-308) We propose applying the CESS to all five Victorian electricity distributors, as none has demonstrated evidence of persistent overspending. Therefore, applying the criteria in our capex incentive guideline, we propose to use forecast depreciation when rolling forward to establish the RAB at the commencement of the 2021–25 regulatory control period.

# AER-final-orangeJurisdictional and legacy issues

1. This attachment sets out our proposed approach on a range of matters raised in consultation. We also address dual function assets.

## F-factor scheme

1. A relevant issue is the Victorian Government f-factor scheme. This scheme provides incentives for Victorian DNSPs to reduce the risk of fire starts due to electricity infrastructure, and to reduce the risk of loss or damage caused by fire starts.[[309]](#footnote-309) The scheme is implemented by an Order issued under the National Electricity (Victoria) Act 2005. This Order confers functions and powers on the AER to regulate the f-factor scheme.

Given that we only have had only two years experience operating the scheme, our preliminary position was that we would maintain the incentive rate of $25,000 per fire for the forthcoming regulatory control period and continue to monitor the effect of the initial incentive mechanism. DSDBI has advised that they will review the scheme in 2014-15.[[310]](#footnote-310) We will apply this scheme in its amended form, as advised by DSDBI.

We also intend to apply to incentive mechanism in a manner similar to the other incentive schemes, such as the STPIS. Hence, we will include an adjustment amount for the “f-factor” in the MAR calculation formula to give effect to the reward of penalty outcomes of actual fire starts under the scheme from the year commencing on 1 January 2016. We will include in this calculation any amounts that due to lag effect have not been paid or recovered in the current regulatory period. This will remain in place unless changed or discontinued by the Victorian Government, subject to any steps necessary to amend or close out the scheme.

## **Dual function assets**

1. Dual function assets are high voltage transmission assets forming part of the distribution network. Transmission network service providers usually operate these assets. Considering transmission assets as part of a distribution determination avoids the need for a separate transmission proposal. Where a network service provider owns, controls or operates dual function assets, we are required to consider whether we should price these assets according to the transmission or distribution pricing principles.
2. The treatment of dual function assets is not a feature of the current Victorian distribution determination or Framework and Approach. This is because none of the distributors owned, controlled or operated dual-function assets at the time of the last determination.
3. No Victorian distributor currently owns, controls or operates 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.[[311]](#footnote-311) Therefore, our decision is that we are not required to, and will not make any determination under the rules regarding dual-function assets.[[312]](#footnote-312)
4. Appendix A – Summary of submissions to preliminary positions F&A

| Respondent | Submission summary | AER response |
| --- | --- | --- |
| Citelum | Submitted that street lighting has been contestable since 2001. Therefore, it argues that all public lighting should be contestable.  Submitted that for the full intent of the Public Lighting Code to come into effect, both the customer and DSNP must be free to negotiate.  Submitted that the vesting of assets in a DNSP is not a legal requirement. The words vest should be removed from any classification. There is no legislative requirement that would compel a public lighting customer to vest an asset.  Submitted that it does not believe that any of the technical requirements are a barrier to allowing a party other than a DNSP to manage and operate street lights.  Queried the need for DNSPs to be involved in approvals. Any council which chooses to retain ownership rights of public lighting should not be inhibited by a DNSP from doing so. DNSPs should only be involved in an advisory role. | As set out in more detail in attachment 1, we consider there is a monopoly element to public lighting assets when included as part of the shared distribution network.  We agree that there is no requirement under Public Lighting Code to vest an asset. We disagree with the claim that the technical requirements are not a barrier to others being more involved in managing and operating street lights. We explain in our response to the Streetlight Group of Councils (below) that the requirement to vest assets arises from the safety framework.  In attachment 1 we classify a new service which will facilitate competition in relation to public lighting assets dedicated to a specific user.  We share Citelum's concern that the approval process is not working as efficiently as it should. However, for the reasons discussed in attachment 1, we accept that there remains a role for DNSPs in public lighting. |
| Streetlight Group of Councils | Submitted that there is no natural monopoly in terms of street lighting services and ultimately these services should be unclassified. The AER should see contestability as the natural development of the market.  Submitted that safety is not a sufficient argument in favour of maintaining current arrangements as there are third party contractors who can provide the service.  Submitted that single OMR tariff and practice of vesting are inhibiting the market. Multiple services that form part of existing public lighting services and these services require individual consideration, which will enable cost reflective pricing. To enable competition, separate O and M/R tariffs should be established. "  Submitted that if the AER classifies any public lighting service as Alternate Control, it must address the aspects currently prohibiting market development.  Proposed a tiered pricing option or revision of the current OMR charges including capital and GIS.  Submitted that the public lighting code only applies to DNSP owned assets.  Submitted that DNSPs are required to keep accurate inventory data for type 7 metering and these costs must be removed from the OMR tariff otherwise it will represent double dipping. There is no natural monopoly in terms of providing type 7 metering. | For the reasons set out in attachment 1 we do not agree that there is no natural monopoly in type 7 metering services.  With regard to there being third party contractors who can provide street lighting services, we agree that at a technical level this is true.  Under the Public Lighting Code street lighting can be built to either the VESI standard, which is simpler and therefore cheaper to build, own and operate or to the general wiring standards that apply elsewhere to all other electricity consumers. The general wiring standard is inevitably more expensive but installations to this standard need not be owned by the distributor. Under safety legislation the VESI standard is only available to an electricity distributor to operate and maintain.  However, this does not mean 3rd party contractors can access installations built to the lower VESI standard without the active supervision of the electricity distributor. We consider that scope exists for distributors to introduce more flexible arrangements to make this service more open to competitive provision but this does not alter the fundamental premise that the service has a monopoly element.  We agree with the Streetlight Group that unbundling of the OMR tariff would improve transparency in regulatory price setting. We have adopted this suggestion. |
| Vector | Supports expanding metering in the Victorian market. Submitted that it does not support exit fees. However, DNSPs should be able to recover the cost of their investment. Any proposed measure should not distort efficient investment; minimise investors' perception of regulatory risk; and not lead to stranded investment. Argued that exit fees do not meet these conditions. They create a barrier to entry and frustrate the policy objective of expanding competition. Vector proposed a range of options in place of an exit fee. | The AER accepts that exit fees will impact the rate of transition to a fully competitive market in metering services. However, under clause 11.17.6 (b) of the NER we also must have regard to the regulatory arrangement which applied in Victoria in regulating the metering service subject to the derogation in clause 9.9C of the NER. Those arrangements applied an exit and a restoration fee to metering services. We must continue to apply an exit and a restoration fee. In determining the components of those fees, the AER will have regard to minimising the negative effects on competition. This will take place in the determination stage of this process. |
| AusNet Services (formerly SP AusNet) | Submitted that there is a lack of clarity in the arrangements for type 5 and 6 metering services in Victoria post derogation. Submitted that any meter installed under the derogation should be classified as direct control; any meter installed after the derogation expires should be unclassified.  Submitted that elective undergrounding is not an ACS service. Instead captured under SP AusNet’s standard control new customer connections and is subject to construction contestability. Construction of reverse feeder should be contestable; the ongoing maintenance of the feeder should be ACS, quoted service.  Submitted that the AER's position in relation to emergency recovery works appears to be an attempt to solve a non-existent problem. These services should not be classified as unclassified; should remain SCS.  Submitted that revenue cap is appropriate for SCS. ACS should be addressed in 3 different groups:  caps on the prices of individual services for ancillary services;  revenue cap for metering services;  defined price path for public lighting.  Submitted an a view that the argument that revenue cap is better aligned with the introduction of efficient prices is flawed because of:  uncertainty around demand has made it more difficult to set tariffs at the right level to recover the approved revenue.  Current forecasting difficulties a revenue cap could be more volatile than under a price cap.  Price caps provide stronger incentives for efficient tariffs than revenue caps.  Supports a revenue cap for metering. Revenue cap is more appropriate for mandated AMI metering services as this is consistent with AMI CROIC.  Supports an exit fee. Submitted that any fee should not leave the DNSP with an uncompensated stranded asset. Clause 7 of CROIC sets out the principles that should be used in determining an exit fee.  Ancillary metering services should be classified as ACS. Proposed the AER should classify inspection of PV installation sites as ACS, with a fee for panels below 5KWh and a quoted service for panels above 5KWh.  Submitted that F-Factor scheme has only applied for two years and it is appropriate that the same incentive rate apply in the 2016-20 regulatory period. Supports the inclusion of the F-Factor adjustment into the MAR calculation formula. Supports the application of the DMIS in its current form. Submitted the need to change the name to Demand Management and Embedded Generation Connection Scheme to give effect to the scheme under the current NER.  Submitted that it is essential to review STIPIS given the introduction of CESS.  Submitted that AER should create a small scale incentive scheme to increase the accuracy of forecasting. DNSPs have little incentive to invest in the accuracy of forecasting.  SP AusNet disagreed with the AER's formulas and sought consideration of an alternative proposal. | We retain the view that ACS is the most appropriate classification for legacy type 5 and 6 metering services. We believe that there is merit in using a revenue cap (not a WAPC) for this service, as the AER must use a revenue cap under the arrangements set in place under the derogation. This need will continue to apply in the early years of the next period. As a classification must apply for the whole period, we classify the monopoly service as ACS. This is discussed in attachment one.  We believe it is necessary to classify two services in respect of type 5-6 and smart metering installations, on the basis that competition is expected to commence in the next period. One classification (ACS) is for metering supplied to the residential/small business (sub 160 MWhrs) sector as a monopoly service. However, for metering provided to this sector as a competitive service the classification will be ‘unclassified’.  The AER will apply an exit fee, as discussed in attachment one. At this stage, the AER has not finalised a view on what components should be included in an exit fee. We will consider this in the determination stage.  We agree with the proposition that as Guideline 14 will apply, services subject to that guideline should be classified SCS.  As discussed in attachment one, we do not accept AusNet’s argument to not re-classify emergency recoverable works.  The submission does not elaborate on the reasons to apply a quoted service approach to PV inspections costs for systems above 5 kW rating. We consider that the classification should be ACS (fee-based).  We note that DSDBI has advised that Victoria will review the f-factor scheme before the end of 2015. We will implement the scheme in its final form, as advised by Victoria.  We note AusNet’s point re the name of the DMIS. We do not intend to rename the scheme at this point of time so as to avoid confusion when we later introduce a Demand Management and Embedded Generation Connection Scheme. As the DMIS currently address both demand management and embedded generation options we are satisfied that the existing scheme should continue.  We will revise the values used as parameters in the STPIS scheme as part of the determination process. However, we do not believe we have sufficient time available to review the STPIS before submissions are due from the Victorian electricity distributors.  We think AusNet Services proposal for a small scale incentive scheme has some merit, but should be examined as part of a wider consultation. However, we do not believe we have sufficient time available to undertake a review before submissions are due from the Victorian electricity distributors.  We have worked with the five DNSPs to address their concerns with the price control formula. This is discussed in attachment 2. |
| CitiPower/Powercor | Submitted that proposed price cap on individual services will mean the businesses will not be assured cost recovery for AMI rollout. Proposed a revenue cap for legacy type 5 and 6 metering services. Revenue cap has a strong guarantee of ensuring the actual costs incurred by businesses.  Revenue control cap mechanism is not applied to the recovery of actual costs. There is an element of forecasting risk. To provide for the full cost recovery of legacy type 5 and 6 metering services within the revenue cap control mechanism, the AER may need to consider the establishment of some type of adjustment mechanism.  Supports ACS for meters installed as part of the AMI rollout as the best mechanism to ensure cost recovery.  Supports the ACS classification for legacy lighting. Submits that there are no regulatory provisions preventing third parties from providing lighting services.  Submitted that for services classified as ACS, the businesses seek the continuation of price caps.  Sought assurances from AER that they accept cost recovery for any tax liability on services, regardless of whether or not the service is classified as SCS or ACS.  Supports an exit fee for recovery of sunk investment in AMI. An exit fee will ensure non-churning customers are no worse off. Also businesses should not be exposed to any investment uncertainty. The exit fee must be determined in accordance with cl 7.2 of the Order in Counsel. Costs should be determine by: depreciated value of the meter, IT communication assets at time of exit, present value of removal meter and present value of communication infill costs. Exit fee revenue adjustment mechanism should allow for: within-period reporting of exit fee revenue, the businesses retain the exit fee revenue and adjustments of the regulated legacy AMI services asset base to reflect the removal of AMI assets and ensure that the metering charge to remaining customers are adjusted accordingly.  Sought a WAPC for legacy type 5 and 6 metering services. WAPC will facilitate competition by providing competitors with the ability to price differently for each metering service  Supports AER's position for connections, other than routine connections. Because of OH&S issues they are reluctant to allow other parties to work on connections. Supports SCS for rearrangement of network assets at customer request and elective undergrounding. Submits that there is no reason why these services should be treated differently to new connections. If they are classified as ACS businesses won't regain total income.  Submits that complex connection works initiated by customers are best included under SCS. This should include rearrangement of network assets and any complex supply abolishment less than 100 amps.  Supports the ACS classification for legacy lighting. No regulatory provisions preventing third parties from providing lighting services. But there are safety concerns.  CitiPower/Powercor disagreed with the AER's formulas and sought consideration of an alternative proposal. | We retain the view that ACS is the most appropriate classification for legacy type 5 and 6 metering services. We believe that there is merit in using a revenue cap (not a WAPC) for this service, as the AER must use a revenue cap under the arrangements set in place under the derogation. This need will continue to apply in the early years of the next period. As a classification must apply for the whole period, we classify the monopoly service as ACS. This is discussed in attachment one.  We believe it is necessary to classify two services in respect of type 5-6 and smart metering installations, on the basis that competition is expected to commence in the next period. One classification (ACS) is for metering supplied to the residential/small business (sub 160 MWhrs) sector as a monopoly service. However, for metering provided to this sector as a competitive service the classification will be ‘unclassified’.  The AER has not considered the question concerning the cost recovery of tax effects. We do not consider it has a bearing in the matters we must address in this F&A.  The AER will apply an exit fee, as discussed in attachment one. At this stage, the AER has not finalised a view on what components should be included in an exit fee. We will consider this in the determination stage.  We agree with the proposition that as Guideline 14 will apply, services subject to that guideline should be classified SCS.  We agree that legacy public lighting is an ACS classification. However, there is evidence in the submission received that the new public lighting service continues to be contentious. We consider the negotiated service classification remains appropriate in these circumstances.  We have worked with the five DNSPs to address their concerns with the price control formula. This is discussed in attachment 2. |
| Jemena | Proposed separate classification for contestable metering and non-contestable metering, with the former being unclassified and the latter being ACS. Submitted that clause 11.17.6(b) of the Order in Council does not mandate ACS classification for all metering; leaving the AER with discretion.  Submitted that the AER has not achieved consistency in the control mechanism for metering (although the AER has explained its position on why it considers change is warranted for the SCS control mechanism, from a WAPC to a revenue cap).  Submitted that it is impractical to apply any form of control for metering other than a revenue cap given that the AER is required to implement two years of revenue cap true-up in 2016 and 2017.  Noted that the exit fee would need to include an operating expenditure component, the control mechanism would needed to be adjusted for any revenue collected from exit fees. It would be too complex to attempt to make such an adjustment for individual price caps or even WAPC. It would be much simpler to implement the adjustment for the revenue cap or an average revenue cap.  Submitted that if the AER’s determination underestimated the number of routine connections, with actual connections exceeding forecast connections then, under a revenue cap, the DNSP might not recover the additional SCS costs. The DNSP will recover the cost of establishing each new connection through the ACS charge, but not the cost of operating, maintaining and repairing the connection. Therefore, the distributor faces a perverse incentive to discourage or delay new connections.  Submitted that if the AER underestimated the cost of establishing a new connection this may also result in a net loss for the DNSP. Under a revenue cap, a new connection does not bring in any additional revenue but it does bring in additional costs. Submitted that all new connections should be SCS.  Submitted that Guideline 14 prevents a DNSP from obtaining a customer contribution that recovers the cost of any augmentation of the shared network. Jemena does not support re-classifying new connections requiring augmentation as negotiated services on the basis that a distributor would need to recover the cost of augmentation up-front.  Proposed that the AER should adopt the approach in the NECF.  Submitted that legacy public lighting should be retained as ACS; however, workable competition exists for new public lighting assets and these services should be unclassified.  Submitted that the statement in the Framework and Approach discussion paper does not meet the requirements of clause 6.8.1(b)(2)(viii) of the NER. The AER guideline is too generic. The guideline does not explain which tools will be applied to assess what types of expenditure and in what circumstances. The F&A should explain how the expenditure forecast guideline will apply in the upcoming revenue determination. AER should explain which tool to apply and how it will select which tool to apply.  Jemena disagreed with the AER's formulas and sought consideration of an alternative proposal. | The AER agrees that it has discretion to classify metering as other than ACS. We retain the view that ACS is the most appropriate classification. We agree that there is merit in using a revenue cap for this service, as the AER must use a revenue cap under the arrangements set in place under the derogation. This need will continue to apply in the early years of the next period. As a classification must apply for the whole period, we classify the monopoly service as ACS. This is discussed in attachment one.  We also agree that it is necessary to classify two services in respect of type 5-6 and smart metering installations, on the basis that competition is expected to commence in the next period. One classification (ACS) is for metering supplied to the residential/small business (sub 160 MWhrs) sector as a monopoly service. However, for metering provided to this sector as a competitive service the classification will be ‘unclassified’.  The AER will apply an exit fee, as discussed in attachment one. At this stage, the AER has not finalised a view on what components should be included in an exit fee. We will consider this in the determination stage.  We do not agree that the AER estimates the number of new connections. The business prepares forecast and must justify that forecast. Only if a forecast is not justified do we vary the forecast. We agree in general with the proposition that as Guideline 14 will apply, services subject to that guideline should be classified SCS. This must remain subject to specific consideration of each service.  We agree that legacy public lighting is an ACS classification. However, there is evidence in the submission received that the new public lighting service continues to be contentious. We consider the negotiated service classification remains appropriate in these circumstances.  The AER does not agree that description of the use of our expenditure assessment guideline is too generic. We will apply every relevant assessment tool to each distribution determination. In doing so, we will strive to be efficient. This does not mean every tool will be applied to every category of expenditure. If initial application of the screening and benchmark tools indicates a greater (or lesser) degree of further investigation is warranted we will respond accordingly. Until there is a proposal before us it is not possible to make such an assessment.  We have worked with the five DNSPs to address their concerns with the price control formula. This is discussed in attachment 2. |
| United Energy | United Energy presented a detailed theoretical argument as to why a Weighted Average Price Cap is preferable to a revenue cap.  Supported the AER’s position that AMI before end of derogation should be regulated as ACS. Sought clarification as to whether any replacement meters post end of derogation due to faults should be treated as ACS.  Submitted that an exit fee should apply.  United Energy propose that elective undergrounding and rearrangement of network assets at customer’s request should be classified as standard control services.  Submitted that lighting connected to a shared distribution network should be classified as ACS. Submitted that United Energy and third parties should be able to compete to operate and maintain assets.  Proposed reducing the lower revenue cap from -5% to -3% cap and retaining +5% cap on upside because. Argued that CESS imposes new additional incentives for DNSPs to not underspend their allowance at the expense of service reliability. Therefore the lower limit cap should be to ensure UE is not unduly penalised where targets are not met; protect UE against the financial impact of random evens; customers are satisfied with existing reliability and -3% would limit exposure of customers to price increases due to investment required to improve reliability.  United Energy disagreed with the AER's formulas and sought consideration of an alternative proposal. | The AER’s view is that efficient pricing structures are able to occur under either a revenue cap or a WAPC. It is theoretically true that the incentive to price efficiently is strongest under a WAPC. However, in recent years considerable difficulty has emerged in accurately forecasting future demand and energy sales. The AER expects this to continue into the next regulatory period as the economy moves through significant restructuring of industry and commerce and shifts in consumer behaviour driven by changes in technology and environmental considerations. We consider that the negative effects of this uncertainty are magnified under a WAPC, relative to a revenue cap. Consequently, the AER considers that a revenue cap is the preferable form of price control for the next revenue period. The AER will apply additional scrutiny over distribution price proposals in the next period to maintain efficient pricing.  We retain the view that ACS is the most appropriate classification for legacy type 5 and 6 metering services. We believe that there is merit in using a revenue cap (not a WAPC) for this service, as the AER must use a building block approach under the arrangements set in place under the AMI CROIC derogation. This need will continue to apply in the early years of the next period. As a classification must apply for the whole period, we classify the monopoly service as ACS. This is discussed in attachment one.  We believe it is necessary to classify two services in respect of type 5-6 and smart metering installations, on the basis that competition is expected to commence in the next period. One classification (ACS) is for metering supplied to the residential/small business (sub 160 MWhrs) sector as a monopoly service. However, for metering provided to this sector as a competitive service the classification will be ‘unclassified’.  The AER will apply an exit fee, as discussed in attachment one. At this stage, the AER has not finalised a view on what components should be included in an exit fee. We will consider this in the determination stage.  We agree with the proposition that as Guideline 14 will apply, services subject to that guideline should be classified SCS.  We agree that legacy public lighting is an ACS classification. However, there is evidence in the submission received that the new public lighting service continues to be contentious. We consider the negotiated service classification remains appropriate in these circumstances.  The AER will consider the variation to revenue at risk under the STPIS as proposed by United Energy in the course of making their distribution determination.  We have worked with the five DNSPs to address their concerns with the price control formula. This is discussed in attachment 2. |
| Department of State Development, Business and Industry (DSDBI) | Submits that a comparison between Queensland and New South Wales are inappropriate given that conditions differ significantly between jurisdictions. In Victoria, barriers to more efficient pricing have been removed, leading to more efficient pricing under WAPC. This is further assisted by smart meters. The form of price control must support the implementation of more efficient pricing structures. The AER should take a forward view of the developing market structure unique to Victoria, rather than relying on retrospective analyses of jurisdictions with quite different market and policy structures. Submitted that if a revenue cap is introduced, efficient costs may vary.  Submitted that it is unclear from the preliminary position paper what adjustment mechanisms the AER is proposing to apply. The AER will need to be equipped with the appropriate resources to scrutinise the distributor's annual pricing proposals for compliance with the pricing principles. Finally uncertainty exists as to what the final pricing principles will be.  Submitted that the Victorian government has not made a final decision on whether to apply NECF. The earliest possible start date is October 2015. Routine connection should be classified as direct control alternative control services. The AER should classify those services requiring augmentation as direct control and standard control because there are instances where the cost incurred by the DNSP may be greater than the revenue recovered from the customer's capital contribution.  Queried the AER's concerns regarding the additional administrative costs associated with the change in control mechanism for type 5 and 6 smart metering services. It would be expected that the administrative costs would be less over the regulatory control period than continuing with existing arrangements for regulating these metering service charges.  Submitted that PV should be either a fee based or quoted service and recommended the AER seek further information from the distributors.  Submits that the national GSL scheme should apply but noted the AER scheme is not aligned with the Victorian GSL scheme. Proposed that AER consider whether GSL payments should be amended to ensure that the reliability payments continue to be made to Victoria's worst served 1 per cent; GSL reliability payments should be amended to reflect the latest values of customer reliability; and the appropriateness of the national GSL parameters given that it excludes the MAIFI.  Advised that DSDBI will review the f-factor scheme in 2015. | The AER’s view is that efficient pricing structures are able to occur under either a revenue cap or a WAPC. It is theoretically true that the incentive to price efficiently is strongest under a WAPC. However, in recent years considerable difficulty has emerged in accurately forecasting future demand and energy sales. The AER expects this to continue into the next regulatory period as the economy moves through significant restructuring of industry and commerce and shifts in consumer behaviour driven by changes in technology and environmental considerations. We consider that the negative effects of this uncertainty are magnified under a WAPC, relative to a revenue cap. Consequently, the AER considers that a revenue cap is the preferable form of price control for the next revenue period. The AER will apply additional scrutiny over distribution price proposals in the next period to maintain efficient pricing.  We note DSDBI’s advice regarding the commencement of the NECF. We will consider any developments in this respect in the course of making the distribution determination.  We note DSDBI’s comments on the costs of administering metering services. Our concern is largely driven by the expectation that in a transition to new pricing arrangements for metering additional scrutiny will be required to ensure the split between regulated and unregulated services is accurate.  We will regulate PV related services as ACS (fee-based).  The AER will update the STPIS parameters where possible in its determination to give effect to new values determined for the major parameters. We will continue to apply the Victoria GSL values.  The AER will apply the f-factor scheme in its amended form, as advised by DSDBI. |

1. Appendix B – Classification of Victorian electricity distributors' distribution services

| Service group | | AER's proposed classification 2016–20 | Current classification 2011–15 |
| --- | --- | --- | --- |
| AER service group—network services | |  |  |
| Planning the distribution network | | 1. Standard control | 1. Standard control |
| Designing the distribution network | | 1. Standard control | 1. Standard control |
| Constructing the distribution network | | 1. Standard control | 1. Standard control |
| Maintaining the distribution network and connection assets | | 1. Standard control | 1. Standard control |
| Operating the distribution network and connection assets for DNSP purposes | | 1. Standard control | 1. Standard control |
| Administrative support (call centre, billing, etc) | | 1. Standard control | 1. Standard control |
| Emergency response | | 1. Standard control | 1. Standard control |
| Location of underground cables (dial before you dig) | | 1. Standard control | 1. Standard control |
| AER service group—connection services | |  |  |
| Routine connections - customers up to 100 amps | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Routine connections - customers above 100 amps | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| New connections requiring augmentation | | 1. Standard control | 1. Standard control |
| Repair and replacement of routine connection | | 1. Alternative control (fee-based) | 1. Alternative control (fee based) |
| Supply enhancement at customer request | | 1. Unclassified | 1. Alternative control (quoted) |
| Customer initiated undergrounding and/or rearrangement of distribution assets serving that customer[[313]](#footnote-313) | | 1. Standard control | 1. Alternative control (quoted) |
| Supply abolishment (>100 amps) | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Supply abolishment (up to 100amps) | | 1. Standard control | 1. Alternative control (fee-based) |
| Temporary disconnect/reconnect services | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| De-energisation of existing connections | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Energisation of existing connections | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| PV & small generator installation pre-approval (up to 5 kW) | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| PV & small generator installation pre-approval (>5kW) | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| AER service group—metering services | |  |  |
| Installation, operation, repair & maintenance, and replacement of type 1-4 metering installations (excluding smart meters) | | 1. Unclassified | 1. Unclassified |
| Collection of meter data, processing and storage of meter data, and provision of access to meter data for type 1-4 metering installations (excluding smart meters) | | Unclassified | Unclassified |
| Operation of type 7 metering installations | | Alternate control | Alternate control |
| AER service sub-group—regulated metering services for type 5, 6 and smart meters | |  |  |
| Installation, operation, repair & maintenance, and replacement of type 5-6 metering installations (including smart meters) | | 1. Alternative control (revenue cap) | 1. Unclassified |
| Collection of meter data, processing and storage of meter data, and provision of access to meter data for type 5-6 metering installations (including smart meters) | | 1. Alternative control | 1. Unclassified |
| Meter exit services | | 1. Alternative control | 1. Unclassified |
| Meter restoration services | | 1. Alternative control | 1. Unclassified |
| Meter investigation | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Special meter read | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Re-test of type 5 and 6 metering installations (including smart meters) for first tier customers with annual consumption greater than 160 MWh | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| AER service sub-group—unregulated metering services for type 5, 6 and smart meters | |  |  |
| Installation, operation, repair & maintenance, and replacement of type 5-6 metering installations (including smart meters) to new customers[[314]](#footnote-314) | | Unclassified | Unclassified |
| AER service group—public lighting services | |  |  |
| Operation, maintenance, repair and replacement - shared public lighting assets | | 1. Alternative control (fee-based) | 1. Alternative control (fee based) |
| Operation, maintenance and repair - dedicated public lighting assets | | 1. Negotiated | 1. Alternative control (fee based) |
| Replacement - dedicated public lighting assets | | 1. Negotiated | 1. Alternative control (fee based) |
| Alteration and relocation of DNSP public lighting assets | | 1. Negotiated | 1. Negotiated |
| New public lights (that is, new lighting types not subject to a regulated charge and new public lighting at greenfield sites) | | 1. Negotiated | 1. Negotiated |
| 1. AER service group—ancillary services |  | | |
| Fault response - not DNSP fault | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Wasted attendance - not DNSP fault | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Service truck visits | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Reserve feeder construction | | 1. Negotiated service | 1. Alternative control (fee-based) |
| Reserve feeder maintenance | | 1. Alternative control (quoted) | 1. Alternative control (fee-based) |
| Temporary supply services | | 1. Alternative control (fee-based) | 1. Alternative control (fee-based) |
| Rearrangement of network assets at customer request, excluding alteration and relocation of public lighting assets | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Auditing design and construction | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Specification and design enquiry fees | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Elective undergrounding where above ground service currently exists | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Damage to overhead service cables caused by high load vehicles | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| High load escorts - lifting overhead lines | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Covering of low voltage lines for safety reasons | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| After hours truck by appointment | | 1. Alternative control (quoted) | 1. Alternative control (quoted) |
| Emergency recoverable works | | 1. Unclassified | 1. Alternative control (quoted) |
| Provision of possum guards | | 1. Unclassified | 1. Unclassified |
| Installation, repair, and maintenance of watchman lights | | 1. Unclassified | 1. Unclassified |

2. Appendix C – Rule requirements for classification
3. We must have regard to four factors when classifying distribution services.[[315]](#footnote-315)
   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, elasticity or gas (as the case may be)
* the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.[[316]](#footnote-316)
  1. 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)[[317]](#footnote-317)
  2. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[[318]](#footnote-318)
  3. any other relevant factor.[[319]](#footnote-319)

1. The rules specify additional requirements for services we have regulated before.[[320]](#footnote-320) They are:
   1. There should be no departure from a previous classification (if the services have been previously classified); and
   2. If there has been no previous classification - the classification should be consistent with the previously applicable regulatory approach.
2. We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[[321]](#footnote-321)
   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.[[322]](#footnote-322)
3. 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 rules.

1. In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules. [↑](#footnote-ref-1)
2. AER, Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016, May 2014. [↑](#footnote-ref-2)
3. NER, clauses 6.8.1(c)(1)–(3). [↑](#footnote-ref-3)
4. When we refer to the Consumer Challenge Panel or CCP, we mean the CCP sub-panel 3 for the Victorian reset. Sub-panel members are Ms Bev Hughson, Ms Fiona McLeod, Mr David Prins and Mr David Headberry. Further information on the CCP can be found at www.aer.gov.au/node/19305. [↑](#footnote-ref-4)
5. AER, Confidentiality guideline, 19 November 2013. [↑](#footnote-ref-5)
6. AER, Consumer engagement guideline for network service providers, 6 November 2013. [↑](#footnote-ref-6)
7. A distribution service is a service provided by means of, or in connection with, a distribution system. NER, Chapter 10. [↑](#footnote-ref-7)
8. We regulate distributors by determining either the prices they may charge (price cap regulation) or by determining the revenues they may recover from customers (revenue cap regulation). [↑](#footnote-ref-8)
9. Appendix B sets out the Victorian distributors' distribution services in more detail. [↑](#footnote-ref-9)
10. See: <http://www.esc.vic.gov.au/Energy/Distribution/RI_FinalPublicLightCodeFollow04ReviewNCM_Apr05> [↑](#footnote-ref-10)
11. Dedicated public lighting assets comprise the pole, bracket and luminaire dedicated to a particular customer. [↑](#footnote-ref-11)
12. In appendix B, our detailed table of service classifications, we use the term 'unregulated' specifically in relation to services provided by the distributors that are not distribution services. These services are outside our jurisdiction. [↑](#footnote-ref-12)
13. NER, clause 6.2.5(a). [↑](#footnote-ref-13)
14. NER, clause 6.12.3(c). [↑](#footnote-ref-14)
15. NER, clause 6.2.5(b). [↑](#footnote-ref-15)
16. NER, clause 6.2.5(b). [↑](#footnote-ref-16)
17. NER, clause 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. [↑](#footnote-ref-17)
18. AER, Electricity distribution network service providers, Service target performance incentive scheme, June 2008, p. 2; AER, Expenditure incentives guideline, 29 November 2013. [↑](#footnote-ref-18)
19. Distributors can seek variations to this range in their regulatory proposals. [↑](#footnote-ref-19)
20. DSDBI, Submission: Preliminary positions on replacement framework and approach, pp. 6-7. If the AER revises the STPIS in time for the Victorian determination we would reconsider whether to apply the GSL in consultation with DSDBI. [↑](#footnote-ref-20)
21. NER, clause 6.6.4. [↑](#footnote-ref-21)
22. AusNet Services, Response to AER F&A Preliminary Positions, 21 July 2014, pp. 24-25 [↑](#footnote-ref-22)
23. Energy and Resources Legislation Amendment Bill 2010, Explanatory Memorandum, p.10. [↑](#footnote-ref-23)
24. DSDBI, Submission: Preliminary positions on replacement framework and approach, p.8 [↑](#footnote-ref-24)
25. NER, clause 6.8.1(b)(1)(ii). [↑](#footnote-ref-25)
26. NEL, s50. [↑](#footnote-ref-26)
27. NER, clauses 6.8.1(b)(1)(ii) and 6.25(b). [↑](#footnote-ref-27)
28. 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 rules. 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 rules. [↑](#footnote-ref-28)
29. Standard control service costs are generally recovered through distribution use of service tariffs paid by all, or most, customers. Alternative control or negotiated service costs are generally recovered from individual customers receiving them. [↑](#footnote-ref-29)
30. NER, clause 6.12.3(b). [↑](#footnote-ref-30)
31. NER, chapter 10, glossary. [↑](#footnote-ref-31)
32. NER, chapter 10, glossary. [↑](#footnote-ref-32)
33. NER, clause 6.7.4. [↑](#footnote-ref-33)
34. NER, clause 6.12.1(15). [↑](#footnote-ref-34)
35. See Appendix B for a list of each distribution service falling within the groups set out above. [↑](#footnote-ref-35)
36. NER, chapter 10, 'distribution system'. [↑](#footnote-ref-36)
37. AER, Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016, May 2014. p.26 [↑](#footnote-ref-37)
38. AER, Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016, May 2014. p.22-24. [↑](#footnote-ref-38)
39. Refer to 'Monopoly services' in section 1.3.6 for a detailed discussion [↑](#footnote-ref-39)
40. Department of State Development, Business and Innovation (DSDBI), Submission: Preliminary positions on replacement frame work and approach (for consultation), July 2014, pp. 4-6. CitiPower/Powercor, 2016-20 Price Reset Project, Framework and Approach Paper, Response to AER Preliminary Positions, 21 July 2014, pp. 6-9. SP AusNet, 2016-20 Regulatory Review - Response to AER F&A Preliminary Positions, 21 July 2014, pp. 5-9. Jemena Electricity Networks (Vic) Ltd, Submission on AER Preliminary Positions, Framework and Approach for 2016-2020 Electricity Distribution Price Review, 21 July 2014, pp. 7-8. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, pp. 9-12. [↑](#footnote-ref-40)
41. NER, clause 9,9C. The derogation will only expire earlier than 31 December 2016 if competition in residential and small business metering services is introduced before this date. [↑](#footnote-ref-41)
42. Advanced Metering Infrastructure Cost Recovery Order in Council 2008. [↑](#footnote-ref-42)
43. The NER, clause 6.2.2.(d)(2), requires that the AER must have regard to the current approach to regulating a service when classifying a service. In clause 11.17.6(b) the AER is required to classify services to which an exit fee or a restoration fees applies under the AMI CROIC as alternative control. [↑](#footnote-ref-43)
44. AEMC, Competition in metering and related services - rule change, Stakeholder workshop 5, 9 October 2014, p.30 [↑](#footnote-ref-44)
45. A 'new customer' includes an existing customer who elects to replace an existing meter. [↑](#footnote-ref-45)
46. NER, clause 6.2.1(c); NEL, s. 2F. [↑](#footnote-ref-46)
47. NER, clause 6.2.1(c). [↑](#footnote-ref-47)
48. NER, clause 6.2.2(c). [↑](#footnote-ref-48)
49. NER, clauses 6.2.1(d) and 6.2.2(d). [↑](#footnote-ref-49)
50. AER, Preliminary positions on replacement for CitiPower, Jemena, Powercor, SP AusNet United Energy, May 2014, appendix B. [↑](#footnote-ref-50)
51. NER, chapter 10, definition of 'network service'. [↑](#footnote-ref-51)
52. Under s. 88A of the Electricity Act 1994 (Vic), the right to supply electricity using a supply network within a distribution area is provided under a 'distribution authority', equivalent to a licence to operate. [↑](#footnote-ref-52)
53. Electricity Act 1994 (Vic), s. 41. [↑](#footnote-ref-53)
54. Licences are issued by the Essential Services Commission of Victoria. [↑](#footnote-ref-54)
55. This is relevant under the form of regulation factors; see NEL, s. 2F(a). [↑](#footnote-ref-55)
56. This is a relevant form of regulation factor: NEL, s. 2F(d). [↑](#footnote-ref-56)
57. NER, clause 6.2.2(c). [↑](#footnote-ref-57)
58. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-58)
59. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-59)
60. NER, clause 6.2.2(c)(3). [↑](#footnote-ref-60)
61. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-61)
62. CitiPower/Powercor, 2016-20 Price Reset Project, Framework and Approach Paper, Response to AER Preliminary Positions, 21 July 2014, p. 3. SP AusNet, 2016-20 Regulatory Review - Response to AER F&A Preliminary Positions, 21 July 2014, p.3. Jemena Electricity Networks (Vic) Ltd, Submission on AER Preliminary Positions, Framework and Approach for 2016-2020 Electricity Distribution Price Review, 21 July 2014, p. 2. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, pp. 6-7.

    . [↑](#footnote-ref-62)
63. NER, clause 6.2.1(c)(4). [↑](#footnote-ref-63)
64. National Electricity (South Australia) Act 1996, schedule National Electricity Law, section 7, which states 'The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system'. [↑](#footnote-ref-64)
65. NER, clause 6.2.1(c)(4). [↑](#footnote-ref-65)
66. NER, clause 6.2.1(c)(4). Also, AER, Stage 1 Framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy, March 2013, p. 20. [↑](#footnote-ref-66)
67. Jemena, Submission on AER preliminary positions, 21 July 2014, p.6, CitiPower/Powercor, Framework and Approach Paper - Response to AER Preliminary Positions, 21 July 2014, p.3 [↑](#footnote-ref-67)
68. SP AusNet, Response to AER F&A Preliminary Positions, p.2. [↑](#footnote-ref-68)
69. Ibid. [↑](#footnote-ref-69)
70. SP AusNet, Response to AER F&A Preliminary Positions, p.10 [↑](#footnote-ref-70)
71. AER, Stage 1 Framework and approach - Ausgrid, Endeavour Energy and Essential Energy, March 2013, p. 20. [↑](#footnote-ref-71)
72. NSW distributors, Response to the AER's preliminary framework and approach paper, August 2012, p. 1. [↑](#footnote-ref-72)
73. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-73)
74. Under NER, clause 6.2.1(d), we must only change classification of a service where a different classification 'is clearly more appropriate'. [↑](#footnote-ref-74)
75. NER, clause 6.2.1(d). [↑](#footnote-ref-75)
76. NER, chapter 10 defines connection services, broadly, as consisting of entry services and exit services. An entry service is a service provided to serve a generator or group of generators, or a network service provider or group of network service providers, at a single connection point. An exit service is a service provided to serve a distribution customer or a group of distribution customers, or a network service provider or group of network service providers, at a single connection point. [↑](#footnote-ref-76)
77. NER, clauses 6.2.1 and 6.2.2 govern our classification decisions for these connection services. [↑](#footnote-ref-77)
78. Essential Services Commission Victoria, Electricity Industry Guideline no. 14 - Provision of services by electricity distributors; and, Electricity Industry Guideline no. 15 - Connection of embedded generation [↑](#footnote-ref-78)
79. Jemena, Submission on AER preliminary positions, 21 July 2014, pp.4-5 [↑](#footnote-ref-79)
80. Essential Service Commission, Electricity Distribution Code, May 2012 [↑](#footnote-ref-80)
81. Jemena, Submission on AER preliminary positions, 21 July 2014, pp. 5-6. SP AusNet, Submission on AER preliminary positions, 21 July 2014, pp. 3-4. CitiPower/Powercor, Submission on AER preliminary positions, 21 July 2014, p. 4. United Energy, Submission on AER preliminary Positions, p. 9. [↑](#footnote-ref-81)
82. SP AusNet, Submission on AER preliminary positions, 21 July 2014, p. 4. [↑](#footnote-ref-82)
83. DSDBI, Submission: Preliminary positions on replacement framework and approach, July 2014 , p.3. [↑](#footnote-ref-83)
84. Victorian Government, Energy Statement, October 2014, p.20 [↑](#footnote-ref-84)
85. DSDBI, Submission: Preliminary positions on replacement framework and approach, July 2014, p.4. [↑](#footnote-ref-85)
86. SP AusNet, Submission on AER preliminary positions, 21 July 2014, p. 4. CitiPower/Powercor, Submission on AER preliminary positions, 21 July 2014, p.5. [↑](#footnote-ref-86)
87. SP AusNet, Submission on AER preliminary positions, 21 July 2014, p. 4. [↑](#footnote-ref-87)
88. NEL, s. 2F(a). [↑](#footnote-ref-88)
89. NER, cl. 6.2.2(c)(5). [↑](#footnote-ref-89)
90. Section 16 of the Electricity Industry Act 2000 (Vic). [↑](#footnote-ref-90)
91. AER, Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016, May 2014., p. 26. [↑](#footnote-ref-91)
92. SP AusNet, Submission on AER preliminary positions, 21 July 2014, p. 4. [↑](#footnote-ref-92)
93. AER staff discussion with Victorian electricity distributors, May 2014 [↑](#footnote-ref-93)
94. In Victoria, when a type 4 meter is used as a replacement for a type 5 or type 6 meter it is deemed to be a type 5-6 meter under a derogation set out in clause 9.9C of the NER. For this F&A type 4 meters installed under clause 9.9C are defined to be 'smart meters'. This is necessary as different regulation requirements exist for type 4 meters installed for general use, as against type 4 meters installed under clause 9.9C. [↑](#footnote-ref-94)
95. All connections to the network must have a metering installation (NER, clause 7.3.1A(a)). [↑](#footnote-ref-95)
96. Schedule 7.2 of the NER refers to metering installation types. Throughout this F&A a reference to a 'meter type' should be taken to a reference to a 'metering installation type', unless the context requires otherwise. [↑](#footnote-ref-96)
97. A derogation is a special class of rules that alter how the NER operates for a whole State (Jurisdictional derogation) or just the named market participant(s) (participant derogation). [↑](#footnote-ref-97)
98. The Victorian distributors are the ‘responsible person’ for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)). [↑](#footnote-ref-98)
99. Interval meters record electricity usage every 30 minutes. [↑](#footnote-ref-99)
100. Such as remote load control by distributors and remote appliance control by customers. [↑](#footnote-ref-100)
101. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-101)
102. Industrial and large customers may use types 1, 2, 3 or 4 meters. These meters are already open to competition and are not regulated by us (NER, clauses 7.2.3(a)(2) and 7.3.1.A(a)). [↑](#footnote-ref-102)
103. NEL, ss. 2F(a)(d). [↑](#footnote-ref-103)
104. As defined in the NER, clause 11.17.1 [↑](#footnote-ref-104)
105. NER, clause 6.2.2(c)(3) and (4). Also, AER, Stage 1 Framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy, March 2013, p. 26. [↑](#footnote-ref-105)
106. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-106)
107. Smart meters are currently identified in the AEMO MSATS[ystem] as type 5 RWD meters. They are also referenced in supporting Victorian regulatory instruments and specifications issued to give effect to the derogation. We do not expect this classification to necessitate a change in MSATS identification or settlement data procedures. This classification is intended to apply generally to customers using up to 160 MWhrs per annum energy usage. Exceptions may apply from time-to-time. E.g. A customer with an energy usage greater than 160 MWh may reduce energy consumption below 160 MWh per annum or a customer using less than 160 MWh may have had a type 4 meter installed for another reason. This would not result in this metering installation automatically becoming regulated. [↑](#footnote-ref-107)
108. For example, a distributor may install a meter as the default supplier of a 'last resort' service - a restoration service. [↑](#footnote-ref-108)
109. NER, clause 6.2.2(d)(2). [↑](#footnote-ref-109)
110. Jemena, Submission on AER preliminary positions, 21 July 2014, p. 12. SP AusNet, Submission on AER preliminary positions, 21 July 2014, pp. 5-8. CitiPower/Powercor, Submission on AER preliminary positions, 21 July 2014, pp. 9. [↑](#footnote-ref-110)
111. Jemena, Submission on AER preliminary positions, 21 July 2014, pp. 3-4. SP AusNet, Submission on AER preliminary positions, 21 July 2014, p. 15. CitiPower/Powercor, Submission on AER preliminary positions, 21 July 2014, pp. 8-9. United Energy, Submission on AER preliminary Positions, p. 12. [↑](#footnote-ref-111)
112. See; <http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv> [↑](#footnote-ref-112)
113. A restoration service applies where a meter is to be supplied under a 'metering provider of last resort ' provision. [↑](#footnote-ref-113)
114. AER, Preliminary positions paper F&A for Vic, December 2013, p. 33. [↑](#footnote-ref-114)
115. Jemena, Submission on AER preliminary positions, 21 July 2014, pp. 7-8. SP AusNet, Submission on AER preliminary positions, 21 July 2014, pp.8-9. CitiPower/Powercor, Submission on AER preliminary positions, 21 July 2014, pp.10-11. United Energy, Submission on AER preliminary Positions, pp.10-11. DSDBI, Submission: Preliminary positions on replacement framework and approach, p.5. [↑](#footnote-ref-115)
116. Vector, Submission on the AER's Preliminary Positions on Replacement F&A for Victorian Distributors, 21 July 2014, pp.1-5. [↑](#footnote-ref-116)
117. A restoration service applies if, as the metering provider of last resort, a distributor reinstates a metering installation or if a distributor replaces a defective installation. [↑](#footnote-ref-117)
118. See; <http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv> [↑](#footnote-ref-118)
119. NER, clause 6.2.1. [↑](#footnote-ref-119)
120. NEL, s. 2F(a). [↑](#footnote-ref-120)
121. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-121)
122. AER, Stage 1 Framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy, March 2013, p. 26. AER, Framework and approach paper – Aurora Energy Pty Ltd, November 2012, p. 25. [↑](#footnote-ref-122)
123. NEL, s. 2F(a) and (d). [↑](#footnote-ref-123)
124. NER, clause 6.2.2(c). [↑](#footnote-ref-124)
125. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-125)
126. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-126)
127. NER, clause 7.4.2(c) establishes that a distributor who is the responsible person for a metering installation must either register with AEMO as a metering provider or engage registered metering providers for such installations. [↑](#footnote-ref-127)
128. NER, clauses 6.2.2(c)(1) and (c)(6). [↑](#footnote-ref-128)
129. NER, clause 6.2.2(c)(6). [↑](#footnote-ref-129)
130. AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012, chapter 4. [↑](#footnote-ref-130)
131. AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012, p. 83. [↑](#footnote-ref-131)
132. AEMC, Energy Market Reform Working Group - bulletin 20, September 2013. [↑](#footnote-ref-132)
133. NER, cl. 6.2.2 (c)(1). [↑](#footnote-ref-133)
134. This is because an equation is used to calculate type 7 metering usage. No physical meter or associated services are necessary. [↑](#footnote-ref-134)
135. Citelum, AER's preliminary positions on a replacement framework and approach 2016-2020, 1 July 2014,p.19. [↑](#footnote-ref-135)
136. Street Light Group of Councils, Preliminary positions on replacement framework and approach (for consultation), July 2014, p.4. [↑](#footnote-ref-136)
137. Available at the AEMO website: <http://www.aemo.com.au/Electricity/Policies-and-Procedures/Metrology-Procedures-and-Unmetered-Loads/NEM-Metrology-Procedure> [↑](#footnote-ref-137)
138. NER, clauses 7.2.1(a), 7.2.8(d) and 3.19(c). [↑](#footnote-ref-138)
139. NEL, s. 2F(a). [↑](#footnote-ref-139)
140. NER, clause 3.6.3 [↑](#footnote-ref-140)
141. NER, clause 6.2.1(d)(1). [↑](#footnote-ref-141)
142. NEL, s. 2F(a) and (d). [↑](#footnote-ref-142)
143. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-143)
144. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-144)
145. AER, Framework and approach paper for Victorian electricity distribution regulation CitiPower, Powercor, Jemena, SP AusNet and United Energy - Regulatory control period commencing 1 January 2011, May 2009, pp.132-133. [↑](#footnote-ref-145)
146. NEL, s. 2F(a). [↑](#footnote-ref-146)
147. NEL, s. 2F(d). [↑](#footnote-ref-147)
148. NEL, s. 2F(a)(d). [↑](#footnote-ref-148)
149. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-149)
150. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-150)
151. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-151)
152. That is, they own the public lighting assets, which are separately recorded in a dedicated public lighting asset base. [↑](#footnote-ref-152)
153. See: <http://www.esc.vic.gov.au/Energy/Distribution/RI_FinalPublicLightCodeFollow04ReviewNCM_Apr05> [↑](#footnote-ref-153)
154. AER, Framework and approach paper for Victorian electricity distribution regulation – CitiPower, Powercor, Jemena, SP AusNet and United Energy for regulatory control period commencing 1 January 2010 (final), May 2009, pp. 25–26; AER, Preliminary positions, Framework and approach paper for Aurora Energy Pty Ltd for regulatory control period commencing 1 July 2012, June 2010, p. 33. [↑](#footnote-ref-154)
155. NEL, s. 2F(d). [↑](#footnote-ref-155)
156. NEL, s. 2F(a). [↑](#footnote-ref-156)
157. NEL, s. 2F(a)(d). [↑](#footnote-ref-157)
158. NER, clause 6.2.1. [↑](#footnote-ref-158)
159. AER, Preliminary positions, Framework and approach paper for Aurora Energy Pty Ltd for regulatory control period commencing 1 July 2012, June 2010, p. 37. [↑](#footnote-ref-159)
160. Street Light Group of Councils, Preliminary positions on replacement framework and approach (for consultation), July 2014. Citelum, AER's preliminary positions on a replacement framework and approach 2016-2020, 1 July 2014. [↑](#footnote-ref-160)
161. Street Light Group of Councils, Preliminary positions on replacement framework and approach (for consultation), July 2014. p.9 [↑](#footnote-ref-161)
162. SP AusNet, Submission on AER preliminary positions, 21 July 2014, pp.11-12 [↑](#footnote-ref-162)
163. SP AusNet, Submission on AER preliminary positions, 21 July 2014, p.3 [↑](#footnote-ref-163)
164. Street Light Group of Councils, Preliminary positions on replacement framework and approach (for consultation), July 2014, p.12 [↑](#footnote-ref-164)
165. Citelum, AER's preliminary positions on a replacement framework and approach 2016-2020, 1 July 2014, p.20 [↑](#footnote-ref-165)
166. AER, Preliminary positions on replacement framework and approach (for consultation) for CitiPower, Jemena, Powercor, SP AusNet, United Energy for the Regulatory control period commencing 1 January 2016, May 2014. p.37 [↑](#footnote-ref-166)
167. Ibid, pp.38-39 [↑](#footnote-ref-167)
168. Street Light Group of Councils, Preliminary positions on replacement framework and approach (for consultation), July 2014, p.7 [↑](#footnote-ref-168)
169. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, p.13-14 [↑](#footnote-ref-169)
170. Citelum, AER's preliminary positions on a replacement framework and approach 2016-2020, 1 July 2014. p.5 [↑](#footnote-ref-170)
171. AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012 [↑](#footnote-ref-171)
172. NER, clause 6.2.2(c). [↑](#footnote-ref-172)
173. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-173)
174. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-174)
175. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-175)
176. NER, clause 6.2.2(c)(3) and (5). [↑](#footnote-ref-176)
177. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, p.7 [↑](#footnote-ref-177)
178. The definition of a distribution system is: A distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system. The consequence is that the assets of the distributor exist on both sides of an intervening distribution system. In the meshed electrical network that forms the NEM this is a common occurrence. [↑](#footnote-ref-178)
179. The guideline is accessible at: <http://www.aer.gov.au/node/19196> [↑](#footnote-ref-179)
180. NER, clause 6.12.3(c). [↑](#footnote-ref-180)
181. NER, clause 6.12.3(c1). [↑](#footnote-ref-181)
182. NER, clause 6.2.5(b). [↑](#footnote-ref-182)
183. NER, clause 6.2.6(a). [↑](#footnote-ref-183)
184. NER, clause 6.2.5(b). [↑](#footnote-ref-184)
185. 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. [↑](#footnote-ref-185)
186. NER, clause 6.2.6(a). [↑](#footnote-ref-186)
187. 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. [↑](#footnote-ref-187)
188. Generally peak demand is referred to as the maximum load on a section of the network over a very short time period. [↑](#footnote-ref-188)
189. NER, clause 6.2.6(b). [↑](#footnote-ref-189)
190. Peak prices include peak energy, demand and capacity prices. [↑](#footnote-ref-190)
191. United Energy, AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, pp. 15-23. [↑](#footnote-ref-191)
192. DSDBI, Preliminary Positions on replacement framework and approach (for consultation), July 2014, 1-2. [↑](#footnote-ref-192)
193. DSDBI, Submission: Preliminary positions on replacement framework and approach, p.2 [↑](#footnote-ref-193)
194. Ibid, p.1 [↑](#footnote-ref-194)
195. AER, Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019, March 2013, p. 48. [↑](#footnote-ref-195)
196. AER, Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019, March 2013, pp. 48–49. [↑](#footnote-ref-196)
197. SCER, Distribution network pricing arrangements, 14 November 2013. [↑](#footnote-ref-197)
198. NER, clause 6.18. These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from Transmission Network Service Providers. [↑](#footnote-ref-198)
199. AER, Final distribution determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, attachments, April 2012, pp. 2–24. [↑](#footnote-ref-199)
200. AER, Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17, April 2012, pp. 20–23.

     This approach means that instead of waiting two years before incorporating the under or over recovery into prices, an estimate (based on nine months of data) used in the calculation of the under or over recovery. This will reduce the likelihood of undesirable price shocks by smoothing the under and over recovery using more updated and accurate estimated and forecast data in the middle year. [↑](#footnote-ref-200)
201. Currently under revenue caps the X-factors perform an adjustment of prices from revenue year on year without taking into account forecasted changes in customer numbers, energy sales and demand. [↑](#footnote-ref-201)
202. AER, Final Framework and approach for Energex and Ergon Energy, April 2014, pp. 59–61. [↑](#footnote-ref-202)
203. Australian Competition Tribunal, [2011] ACompT 1, 2, 3, 4, 7 and 9. [↑](#footnote-ref-203)
204. IPART, Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48, August 2001, p. 10. [↑](#footnote-ref-204)
205. QCA, Final Determination – Regulation of Electricity Distribution, May 2005, p. 30; OTTER, Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices, September 2003, p. 99. [↑](#footnote-ref-205)
206. NER, clause 6.8.1(b)(2)(ii). [↑](#footnote-ref-206)
207. NER, clause 6.12.3(c1). [↑](#footnote-ref-207)
208. Email, United Energy to AER, Re: Proposed meeting to discuss pricing formula for the 2016-2020 reset period,19 September 2014 [↑](#footnote-ref-208)
209. Department of State Development, Business and Innovation (DSDBI), Submission: Preliminary positions on replacement frame work and approach (for consultation), July 2014, p.3. CitiPower/Powercor, 2016-20 Price Reset Project, Framework and Approach Paper, Response to AER Preliminary Positions, 21 July 2014, pp. 12. SP AusNet, 2016-20 Regulatory Review - Response to AER F&A Preliminary Positions, 21 July 2014, p. 18. Jemena Electricity Networks (Vic) Ltd, Submission on AER Preliminary Positions, Framework and Approach for 2016-2020 Electricity Distribution Price Review, 21 July 2014, pp. 8. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, p. 26. [↑](#footnote-ref-209)
210. The basis of the control mechanism is the method used to calculate the revenue to be recovered or prices to be set for a group of services. Clause 6.2.6(b) of the rules states that for alternative control services, the control mechanism must have a basis stated in the distribution determination. We are able to apply a control mechanism to a distributor's alternative control services as set out under chapter 6, Part C of the rules. This involves applying the building block approach, although we may only apply certain elements of the building block approach. Alternatively, we may implement a control mechanism that does not use the building block approach. [↑](#footnote-ref-210)
211. NER, clause 6.8.1(b)(2)(ii). [↑](#footnote-ref-211)
212. NER, clause 6.12.3(c1). [↑](#footnote-ref-212)
213. Street Light Group of Councils, Preliminary positions on replacement framework and approach (for consultation), July 2014, p.22 [↑](#footnote-ref-213)
214. See: <http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements> [↑](#footnote-ref-214)
215. In the preliminary positions paper we included an adjustment term 'A'. Following consultation no sources of a potential adjustment were identified. We now consider this factor is not required for Victoria, and have deleted it in this formula. [↑](#footnote-ref-215)
216. Note that the actual values for revenue at risk for each distributor will be determined in the determination stage. [↑](#footnote-ref-216)
217. AER, Electricity distribution network service providers - service target performance incentive scheme, 1 November 2009. [↑](#footnote-ref-217)
218. Except where a jurisdictional electricity GSL requirement applies. [↑](#footnote-ref-218)
219. 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. [↑](#footnote-ref-219)
220. AER, Electricity distribution network service providers – service target performance incentive scheme, 1 November 2009, clause 2.2. [↑](#footnote-ref-220)
221. AER, Electricity distribution network service providers – service target performance incentive scheme, 1 November 2009, clauses 2.5(d) and (e). [↑](#footnote-ref-221)
222. United Energy, Response - AER's 2016-2020 preliminary positions framework and approach, July 2014, p. 29. [↑](#footnote-ref-222)
223. A distributor may make application for a higher revenue at risk in their determination. [↑](#footnote-ref-223)
224. Supported by Energex, Response to the AER's framework and approach preliminary positions, 19 February 2014, p. 50. [↑](#footnote-ref-224)
225. DSDSBI, Preliminary positions on replacement framework and approach, July 2014, p. 6. [↑](#footnote-ref-225)
226. Ditto. [↑](#footnote-ref-226)
227. AEMC, Review on national framework for distribution reliability, 27 September 2013. [↑](#footnote-ref-227)
228. AEMO, Value of customer reliability issues paper, 11 March 2013; AEMC, Advice on linking the reliability standard and reliability settings with VCR, October 2013. [↑](#footnote-ref-228)
229. NER, clause 6.6.2(b). [↑](#footnote-ref-229)
230. AER, Final decision: Electricity distribution network service providers Service target performance incentive scheme, 1 November 2009. [↑](#footnote-ref-230)
231. NER, clause 6.6.2(b)(1). [↑](#footnote-ref-231)
232. NER, clause 6.6.2(b)(3)(vi). [↑](#footnote-ref-232)
233. 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. [↑](#footnote-ref-233)
234. AER, Electricity distribution network service providers, Service target performance incentive scheme, November 2009, p. 9. [↑](#footnote-ref-234)
235. AEMC, Draft report: Review of distribution reliability outcomes and standards, 28 November 2012. [↑](#footnote-ref-235)
236. AEMO, Value of Customer Reliability Review, Final Report, September 2014 [↑](#footnote-ref-236)
237. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, pp. 29-31, SP AusNet, Response to AER F&A Preliminary Positions, 21 July 2014, pp.21-23 [↑](#footnote-ref-237)
238. NER, Part G. [↑](#footnote-ref-238)
239. United Energy, United Energy's Response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, pp.29-31 [↑](#footnote-ref-239)
240. NER, clause 6.6.2(b)(3)(iii). [↑](#footnote-ref-240)
241. David Headberry, Consumer Challenge Panel member, email to Paul Dunn, 30 September 2014. [↑](#footnote-ref-241)
242. Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS. [↑](#footnote-ref-242)
243. NER, clause 6.6.2(b)(3)(iv). [↑](#footnote-ref-243)
244. NER, clause 6.6.2(b)(3)(v). [↑](#footnote-ref-244)
245. Included in the distributor's approved forecast capex for the next period. [↑](#footnote-ref-245)
246. AER, Efficiency benefit sharing scheme, 29 November 2013. [↑](#footnote-ref-246)
247. CitiPower/Powercor Australia, Response to AER Preliminary Positions, 21 July 2014, p. 12. Jemena, Submission on AER preliminary positions, 21 July 2014, p. 10. SP AusNet, Response to AER F&A Preliminary Positions, 21 July 2014, pp. 21-22. United Energy, AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, p. 31. [↑](#footnote-ref-247)
248. NER, clause 6.5.8(a). [↑](#footnote-ref-248)
249. NER, clause 6.5.8(c). [↑](#footnote-ref-249)
250. AER, Electricity distribution network service providers, efficiency benefit sharing scheme, 26 June 2008. [↑](#footnote-ref-250)
251. We will no longer allow for specific exclusions such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth. We may also exclude categories of opex not forecast using a single year revealed cost approach from the scheme on an ex post basis if doing so better achieves the requirements of the rules. [↑](#footnote-ref-251)
252. AER, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013. [↑](#footnote-ref-252)
253. AER, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013; AER, Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013. [↑](#footnote-ref-253)
254. NER, clause 6.5.8(a). [↑](#footnote-ref-254)
255. NER, clauses 6.5.8(c)(3) and 6.5.8(a). [↑](#footnote-ref-255)
256. NER, clause 6.5.8(c)(2). [↑](#footnote-ref-256)
257. NER, clause 6.5.8(c)(1). [↑](#footnote-ref-257)
258. NER, clause 6.5.8(c)(4). [↑](#footnote-ref-258)
259. NER, clause 6.5.8(c)(5). [↑](#footnote-ref-259)
260. When the distributor spends more on opex it receives a 30 per cent penalty under the EBSS. However, when there is a corresponding decrease in capex the distributor receives a 30 per cent reward under the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward. [↑](#footnote-ref-260)
261. Without a CESS the reward for capex declines over the regulatory period. If an increase in opex corresponded with a decrease in capex, the off-setting benefit of the decrease in capex depends on the year in which it occurs. [↑](#footnote-ref-261)
262. AER, Explanatory statement, capital expenditure incentive guideline for electricity network service providers, November 2013, p. 10. [↑](#footnote-ref-262)
263. 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. [↑](#footnote-ref-263)
264. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 5–9. [↑](#footnote-ref-264)
265. NER, clause 6.5.8A(e). [↑](#footnote-ref-265)
266. NER, clause 6.4A(a); the capex criteria are set out in clause 6.5.7(c) of the NER. [↑](#footnote-ref-266)
267. NER, clause 6.5.8A(c). [↑](#footnote-ref-267)
268. NER, clause 6.5.7(a). [↑](#footnote-ref-268)
269. Consumer Challenge Panel discussions with AER staff 26 June 2014. [↑](#footnote-ref-269)
270. DSDBI, Submission: Preliminary positions on replacement framework and approach (for consultation),July 2014, pp.5-6 [↑](#footnote-ref-270)
271. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 5–9. [↑](#footnote-ref-271)
272. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12. [↑](#footnote-ref-272)
273. 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. [↑](#footnote-ref-273)
274. AER, Explanatory statement, capital expenditure incentive guideline for electricity network service providers, November 2013, p. 10 [↑](#footnote-ref-274)
275. The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS include embedded generation. We consider embedded generation to be one means of demand management, as it typically decreases demand for power drawn from a distribution network. [↑](#footnote-ref-275)
276. For example, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for power drawn from the distribution network. [↑](#footnote-ref-276)
277. NER, clause 6.6.3(a). [↑](#footnote-ref-277)
278. SP AusNet, 2016-20 Response to AER F&A Preliminary Positions, 21 July 2014, p. 24. United Energy, AER's 2016-2020 Preliminary Positions Framework and Approach, p. 31. [↑](#footnote-ref-278)
279. SCER, Demand side participation – proposed rule changes, 18 September 2013.

     See: www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/proposed-rule-changes. [↑](#footnote-ref-279)
280. AEMC, Final report, Power of choice review – giving consumers' choice in the way they use electricity, 30 Nov 2012. [↑](#footnote-ref-280)
281. CitiPower/Powercor Australia, Response to AER Preliminary Positions, 21 July 2014, p. 12. [↑](#footnote-ref-281)
282. NER, clause 6.12.3. [↑](#footnote-ref-282)
283. NER, clause 6.6.3(b). [↑](#footnote-ref-283)
284. NER, clause 6.6.3(b)(1). [↑](#footnote-ref-284)
285. For example, Oakley Greenwood, Valuing reliability in the national electricity market, final report, March 2011. This report was prepared for AEMO. [↑](#footnote-ref-285)
286. NER, clause 6.6.3(b)(2). [↑](#footnote-ref-286)
287. NER, clause 6.6.3(b)(6). [↑](#footnote-ref-287)
288. NER, clause 6.6.3(b)(3). [↑](#footnote-ref-288)
289. NER, clause 6.6.3(b)(4). [↑](#footnote-ref-289)
290. Under the EBSS we can exclude any categories of opex not forecast using a single year revealed cost approach where it would better achieve the requirements (of the EBSS) under cl. 6.5.8 of the NER. DMIA projects are excluded from forecast opex so not considered to be forecast using a single year revealed cost approach. AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, 29 November 2013. [↑](#footnote-ref-290)
291. We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864. [↑](#footnote-ref-291)
292. NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4. [↑](#footnote-ref-292)
293. NER, clause 6.8.1(b)(2)(viii). [↑](#footnote-ref-293)
294. AER, Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution, 29 November 2013. [↑](#footnote-ref-294)
295. Jemena, Submission on the AER preliminary positions, 21 July 2014, p. 11. [↑](#footnote-ref-295)
296. The forecast RAB is the actual RAB at the end of the previous regulatory control period, plus any forecast net capex undertaken in the current regulatory control period, minus any actual depreciation (from assets in place prior to the start of the regulatory control period), minus any forecast depreciation (from net capex undertaken during the regulatory control period). [↑](#footnote-ref-296)
297. This is the sum of actual depreciation for assets in place prior to the start of the regulatory control period and forecast depreciation for net capex to be undertaken during the regulatory control period. [↑](#footnote-ref-297)
298. It is these incentives to reduce expenditure that make historical costs a good indicator of future costs where capex is recurrent and predictable. That is, a distributor's efficient costs are 'revealed' over time. [↑](#footnote-ref-298)
299. AER, Capital expenditure incentive guideline for electricity network service providers, November 2013, pp. 10–12. [↑](#footnote-ref-299)
300. NER, clause S6.2.2B(a). [↑](#footnote-ref-300)
301. NER, clause 6.4A(b)(3). [↑](#footnote-ref-301)
302. NER, clause S6.2.2B(b). [↑](#footnote-ref-302)
303. NER, clause S6.2.2B(c). [↑](#footnote-ref-303)
304. AER, Capital expenditure incentive guideline for electricity network service providers, November 2013, pp. 10–12. [↑](#footnote-ref-304)
305. AER, Explanatory statement, capital expenditure incentive guideline for electricity network service providers, November 2013, pp. 28–29. [↑](#footnote-ref-305)
306. CitiPower/Powercor Australia, Response to AER Preliminary Positions, 21 July 2014, p. 12. [↑](#footnote-ref-306)
307. Jemena, Submission on AER Preliminary Positions, 21 July 2014, p. 10. United Energy, United Energy's response - AER's 2016-2020 Preliminary Positions Framework and Approach, July 2014, p. 31. [↑](#footnote-ref-307)
308. Our ex post capex measures are set out in the capex incentives guideline, see AER, Capital expenditure incentive guideline for electricity network service providers, November 2013, pp. 13–19; the guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective, see AER, Capital expenditure incentive guideline for electricity network service providers, November 2013, pp. 20–21. [↑](#footnote-ref-308)
309. Energy and Resources Legislation Amendment Bill 2010, Explanatory Memorandum, p.10. [↑](#footnote-ref-309)
310. DSDBI, Submission: Preliminary position on replacement framework and approach (for consultation), July 2014, p.8 [↑](#footnote-ref-310)
311. NEL, s50. [↑](#footnote-ref-311)
312. NER, clauses 6.8.1(b)(1)(ii) and 6.25(b). [↑](#footnote-ref-312)
313. This classification applies where a customer contribution is calculated and applied in accordance with ESCV Guideline 14 or, if chapter 5A of the NER applies, the AER's connection guideline. [↑](#footnote-ref-313)
314. A 'new customer' includes an existing customer who elects to replace an existing meter. [↑](#footnote-ref-314)
315. NER, clause 6.2.1(c). [↑](#footnote-ref-315)
316. NEL, s. 2F. [↑](#footnote-ref-316)
317. NER, clause 6.2.1(c)(2). [↑](#footnote-ref-317)
318. NER, clause 6.2.1(c)(3). [↑](#footnote-ref-318)
319. NER, clause 6.2.1(c). [↑](#footnote-ref-319)
320. NER, clause 6.2.1(d). [↑](#footnote-ref-320)
321. NER, clause 6.2.2(c). [↑](#footnote-ref-321)
322. NER, clause 6.2.2(c). [↑](#footnote-ref-322)