

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

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AER reference: 54251

1. Decision to replace framework & approach

On 7 April 2014 we issued a notice under the Rules,[[1]](#footnote-1) inviting submissions on whether it is necessary or desirable to amend or replace the current Framework & Approach (F&A) papers for Victoria. Submissions closed on 18 April 2014 and we received eleven responses.[[2]](#footnote-2)

We consider it necessary to replace the Victorian F&A papers due to the extent of the issues with the current F&A. We consider issues which need to be reviewed are:

* the classification of metering services following the end of regulation of these services under the Advanced Metering Infrastructure Order In Council, and in light of the submissions by Vector Ltd and AGL
* the classification of connection services in light of the possible adoption of the National Energy Customer Framework in Victoria
* the classification of public lighting services in light of submissions received from Citelum, LED Innovations Ltd, Eye Lighting, Trans Tasman Energy Group, and LED Roadway Lighting Ltd regarding the effectiveness of competition in service provision
* the need to review the form of control for direct control services in light of requests from CitiPower and Powercor to move from a weighted average price cap to a revenue cap form of control[[3]](#footnote-3)
* the need to include formulae that give effect to the control mechanisms (that is, how price and/or revenues are to be determined during the regulatory control period)
* the need to outline the application of our revised efficiency benefit sharing scheme
* the likely inclusion of a capital expenditure sharing scheme (to incentivise network service providers to undertake efficient capital expenditure)
* the possible inclusion of a small-scale incentive scheme (pilot or test incentive schemes within an environment that limits the sum of money at risk and the length of time of the scheme)
* the application of the Expenditure Forecast Assessment Guidelines (a nationally consistent reporting framework which allows us to compare the relative efficiencies of network service providers, and decide upon efficient expenditure allowances)
* whether depreciation for establishing the network service providers opening regulatory asset base for the 2021–2025 regulatory control period is to be based on actual or forecast depreciation.[[4]](#footnote-4)

The remainder of this paper sets out—for discussion—our preliminary positions on a replacement F&A for these issues and for other matters to be addressed in the F&A papers.

2. Request for submissions
3. Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) regarding this paper by the close of business, 21 July 2014.
4. Submissions should be sent electronically to: [VICelectricity2016@aer.gov.au](mailto:VICelectricity2016@aer.gov.au)
5. Alternatively, submissions can be mailed to:

Mr Chris Pattas

General Manager, Networks

Australian Energy Regulator

GPO Box 520

Melbourne VICTORIAN 3000

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

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

1. All non-confidential submissions will be placed on the AER's website at [www.aer.gov.au](http://www.aer.gov.au). For further information regarding the AER's use and disclosure of information provided to it, see the ACCC/AER Information Policy, October 2008 available on the AER's website.
2. Enquiries about this paper, or about lodging submissions, should be directed to the Networks Branch of the AER on (03) 9290 1426.
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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).[[5]](#footnote-5) 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 National Electricity Rules (the rules or NER).
3. The preliminary positions paper for 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 preliminary positions on which services we will regulate and how we propose to apply the relevant incentive schemes. It also facilitates early public consultation and assists network service providers prepare regulatory proposals.
4. CitiPower, Jemena, Powercor, SP AusNet, and United Energy (Victorian 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 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 Victorian 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. We have decided to replace the current Victorian F&A for the next regulatory control period. This decision arose following consultation with stakeholders.[[6]](#footnote-6) Our main reason for this decision was because of significant changes to the rules, making elements of the current F&A no longer relevant. All five distributors sought a new or amended F&A. None of the public submissions received opposed the replacement of the current F&A though most submissions did not address this question.
2. The current five year Victorian distribution regulatory control period concludes on 31 December 2015. This paper relates to the regulatory control period commencing 1 January 2016 and sets out our preliminary positions on:

* distribution service classification (which services are to be regulated)
* control mechanisms (how will prices be determined) and 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
* application of the expenditure forecast assessment guidelines
* whether depreciation will be based on forecast or actual capital expenditure
* jurisdictional and legacy issues.

1. We will use the F&A process to commence discussions with the Victorian distributors about the treatment of confidential information as set out in our confidentiality guideline.[[7]](#footnote-7) We encourage the Victorian 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.[[8]](#footnote-8)
2. Following release of this paper, we will consult with interested parties before issuing our final F&A by 31 October 2014. Table 1 summarises the Victorian distribution determination process.

Table 1: Victorian distribution determination process

|  |  |
| --- | --- |
| Step | Date |
| AER publishes preliminary positions F&A for Victorian distributors | 6 June 2014 |
| AER to publish final F&A for Victorian distributors | 31 October 2014 |
| Victorian distributors submit regulatory proposals to AER | 30 April 2015 |
| Submissions on regulatory proposal close | 21 July 2015 |
| AER to publish preliminary distribution determination (prices set here take effect from 1 January 2016) | 31 October 2015\* |
| AER hold public forum on preliminary distribution determination | November 2015 |
| Victorian distributors to submit substitute regulatory proposal to AER | January 2016 |
| Submissions on substitute regulatory proposal and preliminary determination close | February 2016\*\* |
| AER to publish distribution determination for regulatory control period | 30 April 2016 |

\* Date subject to change. To facilitate network tariff pricing proposals an earlier date has been requested by the DNSPs.

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

Source: NER, chapters 6, 11, Part E.

1. 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 Victorian distributors to encourage efficient investment and performance. This overview sets out our preliminary positions on:

* classification of distribution services (which services we will regulate)
* control mechanisms (how we will determine prices for regulated services) and the formulae that give effect to the control mechanisms
* the application of a range of incentives schemes that encourage desired behaviours such as improvements in service quality or efficient capital and operating expenditure
* the application of a range of expenditure forecasting expenditure tools used to test the Victorian 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 and in what form, 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 Victorian distributors recover service costs by averaging them across all customers or only charging those customers benefiting directly from specific services.
3. Our preliminary view is that 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. Similarly, 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. Metering services for types 5 and 6 are currently excluded from classification by a derogation from the NER by Victoria which expires on 31 December 2016. The AER is to regulate these metering services under the derogation until 31 December 2016 and from 1 January 2017 under the NER.
4. Our preliminary position is to classify metering services as alternative control because sub-clause 11.17.6(b) of the NER mandates the classification. We also note there is a strong expectation that in transitioning from the Victorian Government's Order in Council (OIC) an exit fee will apply. We also propose a consolidation of some ancillary network services, removing the need to classify some of these services.
5. Our Victorian distribution service classifications represent our preliminary position for the next regulatory control period.
6. Table 2 provides an overview of the different classes of distribution services for the purposes of economic regulation under the rules.

Table 2: Classifications of distribution services

|  |  |  |  |
| --- | --- | --- | --- |
| Classification | | Description | Regulatory treatment |
| Direct control service | Standard control service | Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network.  Most distribution services are classified as standard control. | We regulate these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services.  The costs associated with these services are shared by all customers via their regular electricity bill. |
| Alternative control service | Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor. | We set service specific prices to enable the distributor to recover the full cost of each service from customers using that service. |
| Negotiated service | | Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services. | Distributors and customers are able to negotiate prices according to a framework established by the rules. We are available to arbitrate if necessary. |
| Unclassified service | | Services that are not distribution services[[9]](#footnote-9) or services that are contestable. | We have no role in regulating these services. |

Source: AER

**Direct control services**

1. The rules contain factors we must consider when determining appropriate 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 will charge customers, or set revenues distributors may recover from customers.[[10]](#footnote-10)

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business.[[11]](#footnote-11) These are central to a distributor's business and the broad customer base uses them. Network services are central to a distributor's monopoly power and are frequently subject to licence restrictions. Therefore, our preliminary position is to classify network services as direct control services. Other distribution services are also subject to limited, or no, supply competition. We therefore also propose to classify as direct control: 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 services those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. We classify most distribution services as standard control, reflecting the integrated nature of an electricity distribution system. We typically regulate these services by determining prices or an overall cap on the amount of revenue that distributors may earn for all standard control services. These standard control services form the core distribution component of an electricity bill.

Our preliminary position is that standard control services include network services and new connections requiring augmentations. These services encompass construction, maintenance and repair of the network, as well as augmenting the network to facilitate connecting new customers.

**Alternative control services**

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. Alternatively, certain customers may request these services. For these services, we set service 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 preliminary position is to classify ancillary network services as alternative control.
2. In Victoria the roll-out of Advanced Metering Infrastructure (AMI) has been conducted under the provisions of their Distribution Licence and regulatory requirements imposed by the Victorian Government. These services are not classified in the current F&A as a consequence. These arrangements are scheduled to expire at the end of 2015, subject to 'true-up' provisions which will have effect in the next regulatory control period.[[12]](#footnote-12) Our preliminary position is, subject to giving effect to the true-up provisions, to classify metering services currently regulated under the Victorian AMI OIC as alternative control services. This is mandated under clause 11.17.6(b) of the NER. This will facilitate more choice for customers. We also note that the provision of these services is likely to become open to more competition in the near future. Furthermore, the range of metering services customers may wish to use (for example, increasing use of the services enabled by smart meters) suggests unbundling these services from standard control is appropriate.
3. We propose to retain the current alternative control classification for routine customer connections, as this is a contestable service in Victoria and costs can be forecast with reasonable certainty. We also propose to retain the current alternative control classification for public lighting, because a defined group of customers purchase these services, for example, local councils.

**Negotiated distribution services**

1. Negotiated distribution services are those services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services. Distributors and customers are able to negotiate services and prices according to a framework established by the rules. We are available to arbitrate if necessary.
2. Our preliminary position is to continue to classify services to install new public lighting technologies as negotiated distribution services. We are interested in stakeholder feedback on whether we could classify all public lighting services as negotiated services. We are also interested in whether new connections requiring augmentation could be classified as negotiated services if Victoria adopts chapter 5A of the NER either by adopting the National Energy Customer Framework (NECF) or by adopting chapter 5A outright.

**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 such services. We refer to these as unclassified or unregulated distribution services.

1. Our preliminary position is to not classify emergency recoverable works.[[13]](#footnote-13) 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 preliminary position F&A. Figure 1 sets out our preliminary positions for classification of Victorian distribution services.

Figure 1: AER's preliminary classification of Victorian distribution services

Source: AER

**Control mechanisms**

1. Following on from service classifications, our determinations must impose controls on direct control service prices and/or their revenues.[[14]](#footnote-14) We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A.[[15]](#footnote-15)
2. The rules require us to decide the control mechanism forms[[16]](#footnote-16) and the formulae to give effect to the control mechanism, but not the basis of the form of control mechanism. In deciding control mechanism forms, we must select one or more from those listed in the rules.[[17]](#footnote-17) These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.
3. In deciding on the form of control mechanism, the rules require us to have regard to specified factors.[[18]](#footnote-18) These include the need for efficient tariffs, administrative costs, previous regulatory arrangements and consistency. In light of the above alternatives and considerations, our preliminary position on the form of control mechanisms for the Victorian distributors are:

* 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 further alignment with the development 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. Therefore our preliminary position is to move to a revenue cap for the Victorian distributors' standard control services.

* alternative control services— caps on the prices of individual services. We consider this approach will provide cost reflective price benefits.

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.[[19]](#footnote-19) 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. A Victorian Government incentive scheme called the F-factor scheme is also administered by the AER. The overall objectives of the schemes are to:[[20]](#footnote-20)

* 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
* (F-factor) reduce the potential for electricity networks to trigger fires.

1. We outline below our preliminary position on the application of each scheme to the Victorian 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 preliminary position is to continue to apply the national STPIS to the Victorian distributors in the next regulatory control period. We will not apply the GSL component as the Victorian distributors are subject to a jurisdictional GSL scheme.[[21]](#footnote-21) Should the Victorian Government move to amend this before the next regulatory control period commences, we will adopt the changed requirements.

Efficiency benefit sharing scheme

1. The efficiency benefit sharing scheme (EBSS) aims 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.
2. As part of our Better Regulation program we consulted on and published version 2 of the EBSS. Our preliminary position is to apply the new EBSS to the Victorian distributors in the next regulatory control period.

Capital expenditure sharing scheme

1. The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.
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 preliminary position is to apply the CESS to the Victorian 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 preliminary position is to continue to apply the DMIS to the Victorian distributors for the next regulatory control period. As we intend the Victorian 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.
3. Following the AEMC's Power of Choice Review rules changes have been introduced that empower the AER to develop an expanded incentive scheme for Demand Management and Embedded Generation. If this scheme is developed in time, it is our intention to apply it to the Victorian distributors. If so, we would implement this through the determination process.

Small-scale incentive scheme

1. The rules state that we may develop a small-scale incentive scheme.[[22]](#footnote-22) We have not developed this scheme. Therefore, we will not be stating our preliminary position on the application of this scheme to the Victorian distributors.

F-factor scheme

1. In the current regulatory control period this scheme has been administered as a separate charge under Victorian legislation. Our preliminary position is that whilst the scheme continues we will incorporate the F-factor scheme in the control formula in the next regulatory control period. In doing so we will also give effect to any residual reward or penalty under the scheme that arises due to the lag that arises between actual events and the measurement of performance, should the scheme be modified or cease to operate.

Application of the expenditure forecast assessment guideline

1. We recently published our expenditure forecast assessment guideline (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 preliminary position is to apply the guideline, including the information requirements to the Victorian 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 Victorian 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 Victorian distributors' regulatory asset base (RAB) for the 2020–2024 regulatory control period. Our preliminary position is to use forecast depreciation to establish the RAB as at 1 January 2020.
2. The depreciation we use to roll forward the RAB can be based on either 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 preliminary position 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

Dual function assets

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

1. None of the Victorian distributors currently own, control or operate any dual-function assets. Therefore, our preliminary position is that we are not required to, and will not make any determination under the rules regarding dual-function assets.[[23]](#footnote-23)

F-factor scheme

1. The Victorian Government has applied the f-factor scheme to provide incentive for Victorian DNSPs to reduce the risk of fire starts due to electricity infrastructure.[[24]](#footnote-24) It was implemented by adding s16C to the National Electricity (Victoria) Act 2005 (the NEVA). Section 16C provides that The Governor in Council, can confer functions and powers, or impose duties on the AER to make determinations on performance targets and incentive mechanisms for the scheme.
2. Subsequently, the Victorian Government published the f-factor scheme order 2011 (the Order) on 23 June 2011 under the NEVA. The Order prescribes that:
   * + - 1. For the first four years of the scheme (2012-15), DNSPs will be either rewarded or penalised at the pre-determined incentive rate of $25,000 per fire for performing better or worse than their respective targets. The reward/penalty amounts will apply to 2014-2016 respectively.
         2. …
         3. After the current regulatory control period (2011-15), we may vary the incentive rates and mechanism of the scheme, such as applying different targets for different parts of the network.

Given that we only have two years operation experience of the scheme, our preliminary position is that we will 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.

# Classification of distribution services

1. This attachment sets out our preliminary position on the classification of distribution services provided by Victorian distributors in 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[[25]](#footnote-25)
* 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.[[26]](#footnote-26)

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.

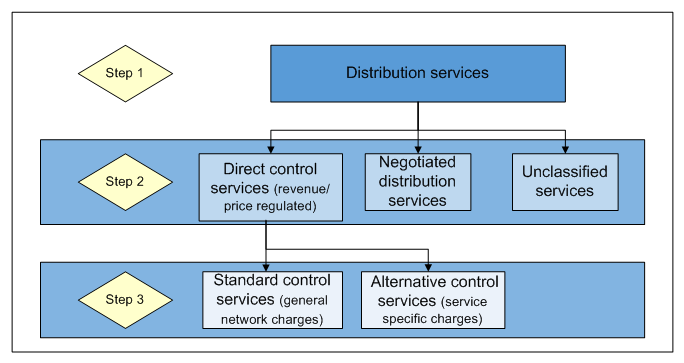
The preliminary positions set out in this attachment are not binding on us or the Victorian distributors. That is, we will consider alternative proposals submitted in response to this preliminary F&A by a distributor or other interested party. Taking into account submissions received, we will publish our final classification decisions in a final F&A. Once we have published our framework and approach paper, we may only change our classification decisions in response to unforeseen circumstances.[[27]](#footnote-27)

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.

1. As illustrated by figure 2:

* 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.[[28]](#footnote-28) 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'.[[29]](#footnote-29)

Figure 2: Distribution service classification process

1. 

Source: NER, chapter 6, part B.

* 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).

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 is to arbitrate disputes where distributors and prospective customers cannot agree. Two instruments support the negotiation process:

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

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

## AER's preliminary position

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 preliminary position is to group distribution services provided by the Victorian 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.[[30]](#footnote-30) They are services provided by means of, or in connection with, a distribution service.[[31]](#footnote-31)
2. We propose to classify distribution services consistently across all the Victorian distributors. Distribution services provided by all distributors will have the same classification. Figure 3 summarises our preliminary classification of the Victorian distributors' distribution services. This section summarises our preliminary positions on the classification of each service group.

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

Source: AER

1. Most distribution services fall within the network services group. 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. The relatively high fixed costs of providing network services mean that 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 more than one distribution network. As competition is absent, we apply the most prescriptive form of regulation to network services—direct control.
2. 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.
3. Connection services relate to connecting new customers to the shared network. In Victoria, we currently classify new connections requiring augmentation as standard control services and routine connections as alternative control services. We propose to retain this approach. However, we may need to re-consider this classification 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.
4. Ancillary network services and some metering services are provided on an 'as needs' basis, requested by specific customers. Therefore, we set charges to allow distributors to recover the full cost of such services from customers using them. Our preliminary approach is to classify these services as alternative control.
5. In Victoria the roll-out of Advanced Metering Infrastructure (AMI) has been conducted by the distributors under the provisions of their Distribution Licences and regulatory requirements imposed by the Victorian Government. These arrangements are scheduled to expire at the end of 2015, subject to 'true-up' provisions which will have effect in the next regulatory period. Our preliminary position is, subject to giving effect to the true-up provisions and consistent with clause 11.17.6(b) of the NER, to classify metering services currently regulated under the Victorian AMI Order in Council as alternative control services.[[32]](#footnote-32)
6. Public lighting maintenance and like-for-like replacement is currently an alternative control service in Victoria. Installation of new public lighting technologies is currently a negotiated service. Our preliminary position is to retain these classifications because public lighting services are provided to specific customers—usually local government councils.
7. 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. At this time, we propose not to classify any Victorian distribution services as negotiated services. However, we are interested in stakeholder views on the possibility of classifying public lighting and new connections requiring augmentation as negotiated services, either now or in the future.
8. Finally, some distribution services are not classified. We propose to not classify 'emergency recoverable works', the provision of possum guards, and the provision of watchmen lights. 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. 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.[[33]](#footnote-33) We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The rules also require us to consider the previous form of regulation applied to services and the desirability of consistency with the previous approach.[[34]](#footnote-34)
3. For services we intend to classify as direct control services, the rules require us to have regard to a further range of factors.[[35]](#footnote-35) 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:[[36]](#footnote-36)

* 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.[[37]](#footnote-37)

## Reasons for AER's preliminary position

1. This section sets out our preliminary position and reasons for the classifications we propose. In turn, this section deals with:

* network services (including emergency recoverable works service)
* connection services
* metering services
* ancillary network services
* public lighting.

### Network services

Distributors provide network services over a shared distribution network to all customers connected to it. Network services are associated with safe and reliable electricity supply.[[38]](#footnote-38) Customers use or rely on network services on a daily basis. Examples include the construction and maintenance of the shared network.

1. Our preliminary position is 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 Victorian distributors each hold an electricity distribution licence for their respective distribution areas.[[39]](#footnote-39) The Electricity Industry Act 2000 (Vic) prevents a person from distributing and supplying electricity unless they hold an authority permitting them to do so.[[40]](#footnote-40) These arrangements provide a regulatory barrier, preventing third parties from providing network services.[[41]](#footnote-41) Therefore, we consider that there is no market for network services for third parties to compete in.
3. The Victorian distributors possess significant market power due to the regulatory arrangements in place.[[42]](#footnote-42) As such, we intend to classify network services as direct control services.
4. We must further classify direct control services as either standard or alternative control services.[[43]](#footnote-43) Our preliminary position is 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.[[44]](#footnote-44) There would be no material effect on administrative costs for us, the Victorian distributors, users or potential users.[[45]](#footnote-45) This is because classifying network services as standard control services is consistent with the current regulatory approach. We currently classify network services in Victorian and all other NEM jurisdictions as standard control services.[[46]](#footnote-46) And finally, distributors provide network services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[[47]](#footnote-47)

Emergency recoverable works

1. Emergency works relate to repairing the distribution network after damage to restore or maintain electricity supply. For example, damage caused by a storm. 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.
2. 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 and this creates a monopoly.
3. 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.
4. For this reason, we intend not to classify emergency recoverable works.[[48]](#footnote-48) By not classifying emergency recoverable works, distributors are not able to recover costs for these services from consumers as a whole. Rather, to be compensated for damage to the network caused by an identifiable party, distributors must seek to recover costs from them. We consider this will establish the right incentives for the Victorian distributors to pursue costs from parties responsible for damage to distribution network assets. Our preliminary approach to this issue is also consistent with our approach to the classification of emergency recoverable works in NSW and Queensland.[[49]](#footnote-49)

### Connection services

1. Chapter 10 of the rules defines connection services.[[50]](#footnote-50) 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
* alter an existing connection to get more electricity from the distribution network than is possible at the moment
* extend the network to reach a person’s premises.

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.[[51]](#footnote-51) Guideline 14 sets out how much a distributor can charge for new works and augmentation associated with all connections to distribution networks. Guideline 15 imposes further conditions on the distributors in processing connection applications from embedded generators. The operation of these guidelines impacts the connection services offered by Victorian electricity distributors.
2. We consider it possible to separate connection services into clearly identifiable components. Table 3 lists our preliminary definitions of each connection type together with our preliminary classification of each type.

Table 3: AER's preliminary position for Victorian connection services

|  |  |  |  |
| --- | --- | --- | --- |
| **Service group** | | **Current classification** | **AER preliminary classification** |
| Routine connections (not requiring augmentation) | Alternative control | | Alternative control |
| New connections requiring augmentation. | Standard control | | Standard control |
| Temporary connections and disconnections | Alternative control | | Alternative control |
| Inspection of PV installation site | Alternative control | | Alternative control |
| Energisation and de-energisation | Alternative control | | Alternative control |
| Supply enhancement at customer request | Alternative control | | Unclassified[[52]](#footnote-52) |
| Operate and maintain connection assets (captured as network services) | Standard control | | Standard control |

We consider each connection type separately below.[[53]](#footnote-53)

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.

1. 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.

New connections requiring augmentation

1. We currently classify new connections requiring augmentation as direct control and standard control services.
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. In some instances the cost incurred by a Victorian distributor of undertaking a connection requiring augmentation may be greater than the revenue recovered from the customer's capital contribution. In such instances, classifying these services as alternative control, negotiated, or unclassified may result in the Victorian distributors being unable to recover the full cost of providing the services.[[54]](#footnote-54) This was the rationale behind the current service classification.
3. As Guideline 14 continues to apply to the Victorian distributors, we propose to continue classifying new connections requiring augmentation as direct control and standard control services.

Transition to NECF

1. The AER's preference is to maintain a common, nationally consistent approach to the matters we regulate. We also favour the competitive provision of connection services wherever practicable. In relation to connection services this is represented by the National Energy Customer Framework (NECF). The NECF is implemented by the inclusion of chapter 5A in the NER. This chapter does not currently apply in Victoria.
2. The connection charging provisions of Victorian Electricity Industry Guideline 14 may cease to apply if Victoria adopts the NECF or if Victoria adopts the application of chapter 5A directly.[[55]](#footnote-55),[[56]](#footnote-56) Victoria may adopt the NECF subject to the resolution of state-specific issues. In either case, the enabling legislation would likely end the reliance on Guidelines 14 and 15 and substitute the adoption of the connections framework contained in Chapter 5A of the NER. This would bring the AER's National Electricity Connection Guideline into operation.[[57]](#footnote-57)
3. Victoria may also adopt the NECF or chapter 5A while maintaining the application of the charging provisions of Guideline 14. Our preliminary discussions with the Victorian Department of State Development, Business & Innovation suggest this option is unlikely to occur. However, if this were to occur, the implications for cost recovery for the Victorian distributors remains as stated above.
4. If Guidelines 14 (and 15) are removed and not replaced with new jurisdictional charging provisions, then our intention is to apply the AER's connection guideline to the Victorian distributors. Our guideline includes provisions for embedded generation. Rules for connecting embedded generation are contained in the NER and enhancements to those rules are being developed by the AEMC.[[58]](#footnote-58) We will apply the NER framework to embedded generation as it evolves.
5. Our connection guideline operates similar to Guideline 14 in most respects. Although charges are calculated differently in some circumstances, the differences are not large except in an environment where a distributor has an increasing price profile. Compared to Guideline 14, the AER Guideline does not transfer as large a cost impact of connecting a new customer to other network customers. The AER Connection Guideline was written with provisions to enable its application if the service classification changes, whereas Guideline 14 is based on an earlier regulatory framework and is inflexible to changes in service category.

Could contestable connections be a negotiated service?

1. We anticipate that the limited contestability provisions of Guideline 14 will continue to apply in any case. If a further level of contestability in connection services is introduced, there would be a possibility of moving to a more light-handed approach to regulation. This could mean classifying new connections requiring augmentations as negotiated services or not classifying them at all. Although the AER supports increased competition in connection services, we stress that for this to apply, relevant changes to the current Victorian regulatory framework must be introduced before the next regulatory determination is made in October 2015.
2. Under a negotiated classification, large customer connections would be subject to a negotiating framework as set out in the rules.[[59]](#footnote-59) The Victorian distributors would need to each prepare a detailed negotiating framework.[[60]](#footnote-60) Amongst other things, these would specify that the distributor must negotiate in good faith, provide prospective service users with enough information for them to negotiate and establish a dispute resolution process.[[61]](#footnote-61)
3. We think the negotiating framework in the rules may provide prospective customers with sufficient confidence that service parameters and prices offered by distributors will be efficient. However, before changing from the current classification approach we seek stakeholder views on this potential change in our classification approach.
4. The Victorian distributors themselves authorise other parties to provide these services through tendering arrangements and specifying the accreditation and other pre-conditions that a tenderer must satisfy. We consider that these arrangements provide a limited barrier to competition.[[62]](#footnote-62) As such, we are comfortable to move from a standard control classification to alternative control. However, in the context of potentially moving away from a direct control classification we think this barrier is more significant.
5. We can contrast the current circumstances with those in NSW. NSW has a well-developed independent authorisation process for accredited service providers and a competitive environment for the provision of premises connection services.[[63]](#footnote-63) Moreover, in most circumstances NSW distributors do not perform connections work themselves.
6. In Victoria, an independent accreditation system for alternative providers of large customer connections would give significant weight to the case for a negotiated service classification. To date, the Victorian Government has not indicated it will establish an independent authorisation system.

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. Because only the distributor may provide temporary connections, our preliminary position is to classify these as direct control services.[[64]](#footnote-64) As they are provided to specific customers, we propose to further classify temporary connections as alternative control services.[[65]](#footnote-65) Our preliminary position is consistent with the current classification.

Operating and maintaining connection assets

1. We consider that once completed, a connection, including large customer connections, 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 preliminary 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.

We seek comment on whether this classification is appropriate and, if so, whether the service should be a quoted service or a fee based service.

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 currently 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[[66]](#footnote-66)
* 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. We consider these factors remain relevant, and propose to retain the classification of energisation and de-energisation services as direct control and alternative control services. These services can now be provided on a remote basis using AMI and at a much lower cost.

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.[[67]](#footnote-67) Accordingly, we do not consider that this service requires classification in Victoria.

### Metering services

1. This section first introduces metering services by explaining the different metering types and different metering services. In doing so, we summarise the categories of metering services we propose to apply and our preliminary classification of the different metering types. Second, we set out our reasons for our preliminary position to the classification of metering services.

Introduction to metering services

1. All electricity customers have a meter that measures the amount of electricity they use.[[68]](#footnote-68) However, not all customers have the same type of meter. There are different types of meters, measuring electricity usage in different ways. The metering installation types are defined in schedule 7.2 of the NER.
2. Large customers use type 1 to 4 meters which provide a range of additional functions compared to other meters. In particular, these types have a remote communication ability. Type 1 to 4 meters are competitively available and we do not currently regulate them—they are unclassified.
3. The Victorian Government mandated a roll-out of 'smart meters' by the five regulated electricity distributors using Victorian regulatory instruments, notably the OIC discussed in chapter 1. Smart meters are interval meters with a communications capability allowing distributors or a third party to read them remotely. Thus, smart meters currently strictly fall within the definition of type 4 metering.[[69]](#footnote-69) Smart meters offer frequent information about usage and facilitate a range of other services.[[70]](#footnote-70) This allows customers to manage their electricity use better.
4. Type 5 metering is defined in the NER as a manually read interval meter whilst type 6 is a manually read accumulation meter. Metering services for types 5 and 6 are currently excluded from classification by a derogation from the NER by Victoria which expires on 31 December 2016. The AER is to regulate these metering services under the derogation until 31 December 2016 and from 1 January 2017 under the NER. This discussion of metering is wholly based on the Victorian specific arrangements continuing to apply under the derogation and transitional rule 11.17.6 of the NER for the next regulatory control period. If the AEMC enacts new rules to introduce competition in metering we expect the enabling Rules will make provision for the transition in Victoria to the new framework. [[71]](#footnote-71)
5. The Victorian distributors are the monopoly providers of type 5 (interval) and 6 (accumulation) meters.[[72]](#footnote-72) Households and other small customers traditionally used these default 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.[[73]](#footnote-73) These meters are manually read. Smart meters have almost entirely replaced type 5 and 6 metering installations in Victoria. This creates a service classification issue in Victoria while current NER metering definitions continue to apply. This is discussed further in the following sections. The Victorian Government has mandated that smart meters must continue to be regulated by the AER in the next regulatory control period, on a basis consistent with the OIC.
6. The Victorian distributors are the monopoly providers of type 7 metering services, which are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections).[[74]](#footnote-74) 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.
7. 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.
8. Type 5 and 6 metering services are currently bundled together and treated as standard control services but are subject to the AMI OIC. This means the current classification of metering services applies to meter installation, provision, maintenance, reading and data management. We consider it useful to separate type 5 and 6 metering services into components. Where we identify a service that refers to a type 5 or 6 metering installation, we also intend that classification to apply to an equivalent service applicable to a smart meter but only those smart meters which replaced a type 5 or 6 meter under the OIC.
9. We propose to separate type 5 and 6 metering into the following components:

* type 5 and 6 and smart meter installation services
* type 5 and 6 and smart meter provision and maintenance.

1. Table 4 summarises the current classification and our preliminary position on the classification of metering services.

Table 4: AER's current and preliminary classification of metering services

|  |  |
| --- | --- |
| Current classification | AER’s preliminary classification |
| Metering types 1 to 4 – unclassified | Metering types 1 to 4 unclassified (excluding smart meters) |
| Metering types 5 and 6 and smart meters – standard control but subject to the AMI Order in Council | The AER intends to classify type 5 & 6 and smart metering services by components: |
|  | a. Metering installation services which include 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 - alternative control |
|  | 1. b. Metering 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 – alternative control |
| Meter type 7 – standard control | Meter type 7 – standard control |
| Auxiliary metering services | Alternative control |

Source: AER

1. Customers pay for metering services, as they do for all other electricity services.

Type 1 to 4 metering services

1. Type 1 to 4 metering services are contestable in Victoria and competitively available.[[75]](#footnote-75) For this reason, our preliminary position is not to classify these services, save for the special case of type 4 where it involves smart meters.[[76]](#footnote-76) Consequently, we will not regulate types 1-3 or type 4 meters which were not installed under the Victorian Government's AMI OIC.[[77]](#footnote-77) This is consistent with the current regulatory approach in Victoria and in other jurisdictions.[[78]](#footnote-78)
2. Type 4 metering installations are remotely read interval meters and apply to any situation with an energy consumption less than 750 MWhrs per annum. Smart meters are remotely read interval meters installed to replace type 5 and 6 metering installations for customers consuming up to 160 MWhrs per annum. Thus, they fall under the type 4 metering definition and not the type 5 definition, which applies to manually read interval meters.
3. 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 OIC and all other type 4 installations. The AMI OIC refers only to installations with a capacity of less than 160 MWhrs per annum. Clause 11.17.6(b) of the NER requires the AER to regulate smart meters and associated equipment in the next regulatory control period on the same basis as the AMI OIC and to classify the service these meters provide as an alternative control service.
4. In this preliminary positions paper a reference to a smart meter is a reference to those meters installed under the AMI OIC and similar meters installed subsequent to the expiry of the derogation as a monopoly service. If the metering definitions in the NER were to be amended to classify smart meters as type 5 or as some other (new) type this distinction may become unnecessary. We do not consider such an amendment is likely in the immediate future.

Type 5 and 6 and smart metering services

1. The Victorian distributors are the monopoly providers of type 5 and 6 and smart meters where they are used to replace a type 5 or 6 meter. Therefore, we propose to apply the direct control classification for these services.[[79]](#footnote-79)
2. Our preliminary position is to classify new type 5 and 6 and smart metering services as alternative control, as distinct from the standard control classification which could otherwise apply to the metering services subject to the AMI OIC. The costs of type 5 and 6 and AMI metering services are currently included in the basic electricity network charges all customers pay, although separate annual charges are made. This is consistent with a standard control classification. As noted earlier, smart meters must be classified as alternative control under clause 11.17.6(b). By changing the classification to alternative control and assuming the market in metering services is opened up to competition, customers who have a new smart meter installed would not have to pay an ongoing charge for a type 5 or 6 meter they no longer use. However, this would result in the unrecovered cost of the past service being transferred to other customers through higher regulated charges. The AMI OIC provides for an exit fee to be recovered from such customers. The AER also proposes to apply an exit fee component to compensate the distributors for the unrecovered cost of the sunk investment.

**Meter installation services**

1. In Victoria, installation of type 5 and 6 and smart metering is not currently contestable.[[80]](#footnote-80) However, we think it possible that contestability in the installation of these metering types may be permitted in future. Unbundling these installation services and separately classifying them as direct control services and further, as alternative control, will facilitate future contestability.[[81]](#footnote-81) By implementing the proposed exit fee the distributors can be compensated for the sunk cost of the current investment in smart metering technology without imposing a cross subsidy burden on the remaining customers with distributor supplied metering.

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

1. We propose to classify metering provision and maintenance 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:[[82]](#footnote-82)

* There is currently a regulatory barrier to any party other than the Victorian distributors providing type 5 and 6 and smart metering provision, maintenance, reading and data services.[[83]](#footnote-83) Under the rules as they currently stand, only the relevant distributor may install a type 5 or 6 or smart meter in its distribution service area.[[84]](#footnote-84)
* Type 5 and 6 metering services are subject to a direct form of regulation in other NEM jurisdictions.[[85]](#footnote-85)
* There is competition available for type 4 meters but not smart meters.[[86]](#footnote-86)

1. We must further classify type 5 and 6 and smart meter provision, maintenance, reading and data services as standard or alternative control services.[[87]](#footnote-87) We consider these services should be alternative control services because they are provided to specific customers[[88]](#footnote-88) and there is potential for contestability in type 5 and 6 and smart metering provision and maintenance services in future.[[89]](#footnote-89)
2. We recognise that the Victorian distributors are currently the monopoly providers of type 5 and 6 and smart metering services.[[90]](#footnote-90) However, separating the costs of meter provision and maintenance, reading and data services from shared network charges will enhance competition should contestability for these services change.[[91]](#footnote-91) If charges for these services remain bundled in distribution charges, any future changes in contestability may be far less effective.

Another relevant factor[[92]](#footnote-92) to be considered is creating a more transparent and accurate way of providing customers with costing information. Making metering costs transparent under an alternative control classification would allow customers to make more informed choices on metering provision, maintenance, reading and data services.

Power of Choice review

1. As set out above, we propose to unbundle type 5 and 6 and smart metering services from standard network charges, separate them into different categories of metering services and classify each component as alternative control. Our preliminary approach is consistent with the Australian Energy Market Commission's (AEMC) final report for its Power of Choice Review.[[93]](#footnote-93) The AEMC designed its recommendations to promote the investment in, and use of, advanced metering infrastructure (‘smart’ metering). It considers there will be demand management benefits for customers, retailers and distributors.
2. The AEMC recommended metering costs be unbundled from shared network charges.[[94]](#footnote-94) Also, that provision of metering services be contestable. While we do not determine the contestability of metering services, our preliminary approach to classification would facilitate contestability should legislative changes occur to open up the market. The AEMC has commenced consultation on rule changes to introduce competition in metering services.[[95]](#footnote-95)
3. Based on the analysis above, our preliminary position is that it is clearly more appropriate to classify type 5 and 6 and smart metering provision, maintenance, reading and data services as alternative control services. The AER may revise this position in its determination if necessary to achieve a position consistent with Rule changes adopted by the AEMC.

Exit fees

1. We welcome submissions on the form and scope of an exit fee. 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 welcome submissions on the form and scope of an exit fee. Submissions should address how this charge should be calculated.

Type 7 metering services

1. A type 7 metering service is a metering installation that does not measure the flow of electricity. Examples include public lights or security 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 Victorian 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.[[96]](#footnote-96) For this reason, an alternative provider has limited incentive to enter the market for the provision of type 7 metering services. The Victorian distributors are already performing data management services for type 5 and 6 meters. Providing type 7 metering services is a logical extension for the Victorian distributors to undertake.
3. We consider that there is no potential to develop competition in the provision of type 7 metering services.[[97]](#footnote-97) 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—standard 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.[[98]](#footnote-98) Therefore, our preliminary position is to continue to classify type 7 metering services as standard control services.

Auxiliary metering services

1. The Victorian 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 metering services, to which most auxiliary metering services relate.[[99]](#footnote-99) For example, only the Victorian distributors can perform an additional meter read as the monopoly provider of type 5 and 6 meter reading services.[[100]](#footnote-100) 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 Victorian distributors provide auxiliary metering services to specific customers, we propose to classify them as alternative control services.[[101]](#footnote-101)
4. Under our preliminary 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 preliminary approach would facilitate this.

Metering classification summary

1. On the basis of our above analysis, our preliminary position is to classify metering services as summarised in table 5.
2. Table 5: AER's preliminary position to classifying metering services

|  |  |
| --- | --- |
| AER's preliminary position |  |
| Service | Preliminary classification | |
| Type 1 to 4 metering services (excluding smart meters) | Unclassified |
| Type 5 to 6 metering services - before AMI expiry | Unclassified |
| Type 5 to 6 and smart metering services - after AMI expiry | Alternative control |
| Metering provision, maintenance, reading and data services | Alternative control |
| Type 7 metering services | Standard control |
| Auxiliary metering services, including exit fees | Alternative control |

1. 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'.[[102]](#footnote-102)

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 lifting overhead lines for high load vehicles, or after hours service provision. Ancillary network services involve work on, or in relation to, parts of the Victorian distributors' distribution network. Therefore, similar to network services only the distributor can perform these services.

We consider that, similar to network services, there is a regulatory barrier preventing any party other than a Victorian distributor providing ancillary network services.[[103]](#footnote-103) 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 available to the distributors also likely prevents alternative providers from competitively providing ancillary network services.[[104]](#footnote-104) These factors contribute to our preliminary view that, like network services, the Victorian distributors possess market power in providing ancillary network services.

Because of these barriers to competition from alternative service providers, we propose to classify most ancillary network services as direct control services.[[105]](#footnote-105) Two ancillary network services, provision of possum guards and provision of watchmen lights, are currently not classified. We propose to continue not classifying these services. We understand that watchmen lights are not part of Victorian distributors' distribution systems and that there are alternative providers of both watchmen light and possum guard services.

Having decided to apply a direct control classification to the remainder of ancillary network services, we must further classify these 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.[[106]](#footnote-106) 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.[[107]](#footnote-107) 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.[[108]](#footnote-108) This results in costs that are more transparent for customers. Additionally, the note to clause 6.2.2(c)(5) of the rules state:

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. The Victorian distributors operate and maintain public lighting throughout the state as part of their distribution networks.[[109]](#footnote-109) The distributors provide these services on behalf of 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.[[110]](#footnote-110) However, we have consistently defined the following public lighting services in other distribution determinations as the:

* operation, maintenance, repair and replacement of public lighting assets
* alteration and relocation of public lighting assets, and
* provision of new public lighting.[[111]](#footnote-111)

1. We also propose to continue to include emerging public lighting technology (emerging technology) as part of the public lighting services group. 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. Emerging technology relates to luminaires that the Victorian distributors do not provide, or may not exist, at the time of our distribution determination. Such emerging technology may become available during the next regulatory control period. A distinction must also be made for greenfield sites such as new estate developments. These 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)

1. Our preliminary 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.
2. However, we think there are customer benefits to classifying public lighting as a negotiated service. This section first discusses our reasons for our preliminary position to classify public lighting as alternative control. Second, we discuss why public lighting may be suitable for classification as a negotiated service.
3. While the Victorian distributors do not have a legislative monopoly over these services, a monopoly position exists to some extent.[[112]](#footnote-112) This is because the Victorian distributors own the majority of public lighting assets.[[113]](#footnote-113) 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.[[114]](#footnote-114) Based on the above analysis, our preliminary position is to classify public lighting services, excluding emerging technology, as direct control services.[[115]](#footnote-115) This is consistent with its current classification.
4. As direct control services, we must further classify public lighting services as either standard control or alternative control services.[[116]](#footnote-116) Our preliminary position is to classify public lighting as an alternative control service, consistent with current arrangements. 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.[[117]](#footnote-117) There would be no material effect on administrative costs to us, Victorian distributors, users or potential users, because we are retaining the current classification.[[118]](#footnote-118) The Victorian distributors can directly attribute the costs of providing public lighting services to a specific set of customers, such as local government councils.[[119]](#footnote-119)

Emerging technology and greenfield sites

1. Our preliminary position on emerging technology is to continue the existing classification as a negotiated service. In our initial consultation we received submissions from Trans Tasman Energy, Citelum, LED Innovations and LED Roadway Lighting. The common theme of these submissions was to raise concern that the current regime for implementing new technology in lighting was slow and cumbersome. We agree. However, this is because of the need to satisfy a raft of safety, quality and energy usage requirements before the luminaires can be connected.
2. We note these submissions had not suggested this was because of the current service classification. Rather, the issues raised tend to confirm that there remains a role for distributors in relation to many types of public lighting. 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 service should continue to be a negotiated service.
3. In the recent consultation we received no comment on the classification of greenfield sites. We note that the Public Lighting Code remains the primary instrument regulating public lighting installations in Victoria. Distributors provide services necessary to implement the Code. Unless the Code is amended by the Victorian Government, we expect current practices to continue. Our preliminary position is to continue the current classification of greenfield sites as a negotiated service.

Is the current classification of greenfield sites and/or emerging technology as a negotiated service correct? Comments are sought on whether any other classification would be preferable for either service and if so, why?

Could public lighting be a negotiated service?

1. Our preference is to allow the competitive provision of services wherever practicable. We note the dissatisfaction expressed in submissions with the current approach to public lighting. While our preliminary position is to continue the current classification approach, we think there may be a case to move to a negotiated service classification for public lighting services as a whole. We do not consider, at this time, a further move to not classify public lighting services is warranted. However, there may be scope to allow distributors and customers to negotiate public lighting services under the framework established by the rules.
2. Local councils are experienced in procuring services and are large customers relative to households and small businesses. Also, local councils are not required to ask the distributors to provide, operate and maintain their street lighting assets. As public lighting customers, they have the option of providing (and owning), operating and maintaining their own lights, thereby avoiding the distributor's physical public lighting services (by using an ‘energy only’ service). In essence, they may ask the developer of a greenfield site to vest the public lighting assets to the councils, rather than the distributor. Or they may only employ the distributor to replace failed light bulbs. We consider these options could provide some countervailing power to local councils and place some competitive pressure on the pricing of public lighting services.
3. Public lighting is also an area of rapid technological innovation. Emerging technologies offer more energy efficient lighting services. We know that municipal councils value this as a new offering to their ratepayers. When public lighting is classified as an alternative control service, we must make a determination on the prices customers will pay. A distributor must ask us to approve its proposed capital and maintenance charges for an emerging technology, such as a new luminaire, within the regulatory control period. This process adds a time delay to the adoption of emerging technologies. Allowing local councils to negotiate the price of their public lighting services may facilitate faster uptake of new lighting technologies.
4. We are not aware of calls for greater levels of involvement in setting prices or service levels for public lighting that would in turn suggest a different approach to classification. Our views on this issue are preliminary and yet to be informed by stakeholder views. We encourage stakeholder submissions on this issue and will seek to liaise with local councils and other interested stakeholders on the potential to change our current approach.

We seek stakeholder submission on the potential to classify all public lighting as a negotiated service.

## AER's preliminary approach to service classification

1. In summary, we intend to group and classify the Victorian distributors' distribution services as set out in Appendix B.

# Control mechanisms

1. This attachment sets out our proposed form of control mechanisms to apply to the Victorian distributors' direct control services for the 2016–20 regulatory control period. This section 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. This paper states our preliminary positions, together with our reasons, on the form(s) of the control mechanism(s) to apply to direct control services in the determination for the 2016–20 regulatory control period. 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. Attachment 1 provides our proposed classification of Victorian distribution services.
3. We can only approve the forms of control in a distributor’s regulatory proposal if is identical to that set out in our F&A paper.[[120]](#footnote-120) 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.[[121]](#footnote-121)

## AER's preliminary position

1. Our preliminary position is to apply the following forms of control in the 2016–20 regulatory control period:

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

## 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[[122]](#footnote-122)
* the formulae to give effect to the control mechanisms
* the basis of the control mechanism[[123]](#footnote-123)

1. The rules set out the control mechanisms that may apply to both standard and alternative control services:[[124]](#footnote-124)

* 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[[125]](#footnote-125)

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 maximum allowable revenue (MAR) for each year of the regulatory control period. Distributors must then recover revenue equal to or less than the MAR. 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 MAR. 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 MAR in future years. This operation occurs through an 'overs and unders' account, whereby any over-recovery (under-recovery) is deducted from (added to) the MAR 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 MAR 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 MAR per unit of output.

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

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

In considering our preliminary position, 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.[[126]](#footnote-126)

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.[[127]](#footnote-127)
* 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.[[128]](#footnote-128)

### 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.[[129]](#footnote-129) 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.[[130]](#footnote-130)

## 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. Firstly, because for the majority of distributors the costs of supply are fixed or relate to peak demand, efficient prices will be structured around fixed or peak prices.[[131]](#footnote-131) Secondly, because customers’ willingness to pay for connection to the network is generally higher than for electricity consumption, where the price must be set above the cost of supply the largest margin is likely to be applied to fixed (connection) prices.

1. We note that similar to other jurisdictions (regardless of control mechanism) Victorian distributors recover significant revenue from flat energy tariffs which are unrelated to the peak periods of demand by time or location.
2. 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.
3. We consider that this incentive is unlikely to give rise to inefficient pricing for Victorian distributors. We consider that the majority of distributors' variable costs are caused by augmentations and connections (where demand for connections is likely 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. 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.
4. To illustrate relative efficiency of different tariff structures, we previously drew a number of comparisons between the Queensland distributors, under a revenue cap, and the NSW distributors under a WAPC. In general, we concluded that tariff structures that include a greater reliance on time of use or load control tariffs, or fixed charges are more efficient than tariffs based simply on the accumulated energy consumption. We published further discussion on the efficiency of different tariff structures earlier this year.[[132]](#footnote-132). We note Victoria now has a high penetration of smart meters. Therefore, it is well positioned to implement more efficient pricing structures.

In reviewing the form of control in NSW[[133]](#footnote-133) we found that a WAPC had not encouraged the NSW distributors to adopt efficient prices, despite theory that suggested this should be an outcome of a WAPC. The Victorian distributors did commence to develop new tariff structures but this work was stalled by the introduction of a moratorium on new pricing changes implemented by the Victorian government. The moratorium has since been lifted.

Figure 4 below allows us to compare the Queensland distributors under the existing revenue cap and the WAPC the NSW distributors have operated under in recent years. From the figures below we can see that despite operating under a revenue cap, the Queensland distributors have a higher proportion of revenues raised through prices we regard as more efficient, such as fixed price components and prices for controlled loads. We concluded from this evidence that a revenue cap has not discouraged the adoption of more efficient tariff structures. We continue to rely on the work undertaken comparing NSW and Queensland.

A significant issue in recent times has been the widespread difficulty experienced in all sectors of the NEM in accurately forecasting customer demand. Despite economic growth and renewed business activity across the nation following the global financial crisis, energy demand has continued to exhibit a downward trend. This trend is widely attributed to a range of factors including higher energy efficiency, widespread penetration of solar, higher prices and increased customer concern about climate change. This makes the future forecasting of demand a very difficult task for all in the industry

The AER sought comment from the Consumer Challenge Panel, sub-panel 3 on its view of the choice between a revenue cap and a WAPC. The sub-panel replied by letter:[[134]](#footnote-134)

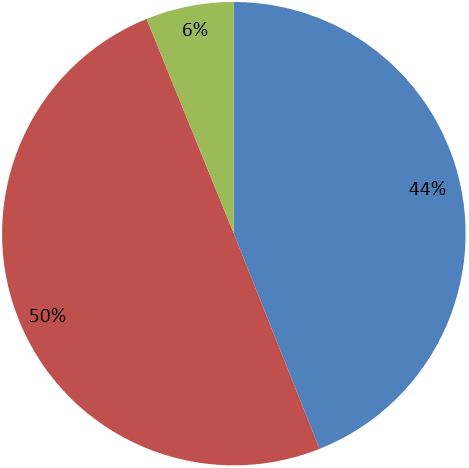
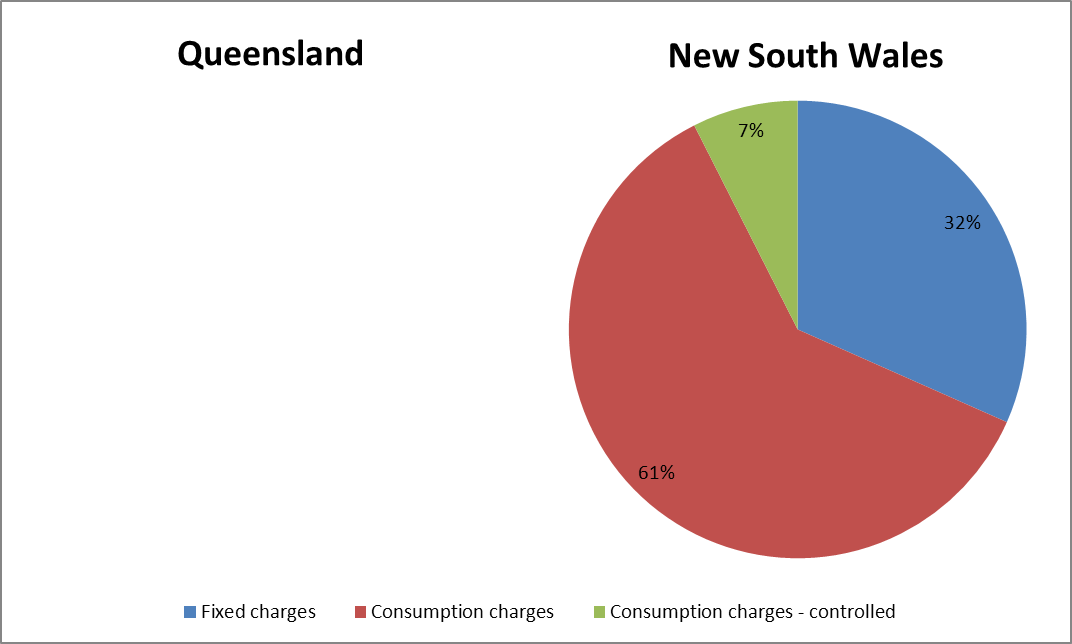
…the AER should stress that the WAPC approach presents a considerable concern to consumers as its operation can allow systematic recovery of more revenue than considered appropriate by the regulator, a trend exacerbated by information asymmetry between the DNSPs and the regulator and consumers.

SP3 also considers that the draft F&A should specify a single form of the control mechanism to apply in a given region as the arguments in favour of the revenue control mechanism  apply equally to all the DNSPs operating in the same region. This point is specific as SP3 has concerns that one or more of the DNSPs in the Victorian region might seek a WAPC form of control while the others accept a revenue cap control.

In promoting the revenue control mechanism, SP3 recognises that the revenue control mechanism transfers the risk of consumption variation from the DNSPs to consumers. This highlights the importance of the AER improving its forecasting capabilities for opex and capex, particularly given the increased discretion under the revised National Electricity Rules for the AER to reject a forecast and replace it with its own.

The CCP also identified the need of the AER to have the best possible forecasts of capex and opex to support its determinations as a relevant factor in determining the form of control. We consider the risks to consumers of incurring higher costs are exacerbated under a WAPC in a situation where an unanticipated negative trend in the rate of energy use may continue. Consequently, we consider this risk is better managed under a revenue cap.

Figure 4: Queensland and NSW distributors' revenue type



Source: AER. Qld DNSPs' revenue type is for 2012–13 while NSW DNSPs' revenue type is for 2008–09.

### 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 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 revenue risk to distributors. This would likely lead to increased costs through risk minimisation strategies. Furthermore, the change to a revenue cap in Victoria will likely lead to reduced administrative costs to users and us due to consistency across and between regulatory arrangements. We are proposing the introduction of a revenue cap in South Australia, New South Wales will be under a revenue cap in 2014–19 and Tasmania is already operating under a revenue cap. This consistency will lead to reduced administrative costs for us through standardisation of modelling approaches, incentive schemes and consultation requirements.

### Existing regulatory arrangements

1. We consider that consistency across regulatory control periods is generally desirable. However, it is not primary to our considerations in this instance. We consider that desirability 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. Desirability needs to be weighed against the other factors under clause 6.2.5(c) of the rules. The outcomes under the other factors reveal outcomes that further 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 distributors' 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 2.3.8 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 in New South Wales.[[135]](#footnote-135)

### Pricing flexibility and stability

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. We assess these estimates rigorously as substantial revenue is at risk which can result in significant changes in profit for distributors.

### 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.[[136]](#footnote-136)
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,[[137]](#footnote-137) we designed the unders and overs account as a rolling account with an estimate year to help smooth the price adjustments year on year.[[138]](#footnote-138) 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.[[139]](#footnote-139)
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 consider that the WAPC can result in greater price instability across regulatory control periods compared to the revenue cap. This issue is particularly pronounced 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) if a trend of falling demand was evident.
5. 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 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.

Figure 5: Typical residential customer electricity charges

Source: AER. The graph is based on annual consumption of 4250 kWh and is inclusive of GST.

### 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 many formulations for designing 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.[[140]](#footnote-140) 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.[[141]](#footnote-141)

### 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.[[142]](#footnote-142) 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.[[143]](#footnote-143)
2. Below is a preliminary formulae to apply to standard control services. We consider that the formula gives effect to the revenue cap.
3. (1)  i=1,...,n and j=1,...,m and t=1,...,5
4. (2) 
5. (3) 
6. Where:
7. is the maximum allowable revenue in year t.
8. is the price of component i of tariff j in year t.
9. is the forecast quantity of component i of tariff j in year t.
10. is the annual smoothed revenue requirement in the Post Tax Revenue Model for year t.
11.  is the sum of incentive scheme adjustments in year t. To be decided upon in the final decision.
12.  is the sum of end-of-period adjustments in year t. Likely to incorporate but not limited to adjustments from the transitional regulatory control period.[[144]](#footnote-144) To be decided upon in the final decision.
13.  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 upon in the final decision.
14. is the percentage increase in the consumer price index. To be decided upon in the final decision.
15. is the X-factor in year t. To be decided upon in the final decision.

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

1. Our preliminary position is to apply caps on the prices of individual services in the next regulatory control period to all alternative control service. We propose classifying the following services as alternative control services:

* type 5 and 6 and smart metering services
* ancillary network services
* public lighting.

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.[[145]](#footnote-145) 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 Victorian 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 preliminary 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 preliminary view is that there will be no material impact on administrative costs for ancillary network 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 create greater cost reflectivity for these service charges to customers in a user-pays environment. We consider these benefits warrant a short term increase in administrative costs. In any event, we have previously noted that the AER is obliged by clause 11.17.6(b) to make this classification.

### Existing regulatory arrangements

1. We consider consistency across regulatory control periods is generally desirable. However, we consider consistency across regulatory control periods should not be our primary consideration in determining a control mechanism in this instance for alternative control services. Our consideration of other factors in clause 6.2.5(d) of the rules leads us to the conclusion that the use of price caps for individual services would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.
2. For metering services, a change in regulatory arrangements will be made regardless of the control mechanism we determine because we propose reclassifying these services. For public lighting and ancillary network services, our preliminary position 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 considerations 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 able to compensate for such reductions by increasing the price on non-competitive services. This will enhance cost reflectivity on 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 the F&A paper.[[146]](#footnote-146) 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 paper.[[147]](#footnote-147)

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

1. Below is a preliminary 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:
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
7. is the percentage increase in the consumer price index. To be decided upon in the final decision.
8. is the X-factor for service i in year t. To be decided upon in the final decision.
9. is an adjustment factor. Likely to include, but not limited to adjustments for residual charges when customers choose to replace assets before the end of their economic life.

# Incentive schemes

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

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

## 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 Victorian distributors in the next regulatory control period.
2. Our national distribution STPIS[[148]](#footnote-148) provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).
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[[149]](#footnote-149) experiencing service below a predetermined level.[[150]](#footnote-150)

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.[[151]](#footnote-151) 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 limit price volatility for customers.[[152]](#footnote-152) A distributor proposing a delay must provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers.
2. Our national STPIS currently applies to the Victorian distributors. CitiPower, Jemena, Powercor, and United Energy are currently subject to financial penalty or reward of ±5 per cent through an s-factor adjustment to revenue. SP AusNet is currently subject to financial penalty or reward of ±7 per cent. GSLs are provided for through the Victorian Electricity Distribution Code and Public Lighting Code, so the GSL component of the AER's STPIS will not apply.[[153]](#footnote-153)

### AER's preliminary position

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

* set revenue at risk for each distributor within the range ±5 per cent. However, we will reconsider our preliminary position once we see the outcome of work underway by the AEMC.[[154]](#footnote-154)
* segment the network according to our interpretation of the Standing Committee on National Regulatory Reporting Requirements (SCONRRR) feeder categories (CBD, urban, short rural and long rural)
* set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index of SAIFI) and customer service (telephone answering) parameters
* set performance targets based on 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 and performance targets
* apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates.

1. We will not apply the GSL component if the Victorian distributors remain subject to a jurisdictional GSL scheme.
2. We aware of policy reviews indicating the need to reform the STPIS. The AEMC recently conducted a review of distribution reliability frameworks in the NEM[[155]](#footnote-155) and is currently developing advice on common definitions of distribution reliability measures.[[156]](#footnote-156) The Australian Energy Market Operator (AEMO) is currently conducting analysis on how willing consumers are to pay for improvements in network reliability.[[157]](#footnote-157) We consider there is likely to be inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our draft determinations for the Victorian distributors in October 2015. Nonetheless, if the opportunity presents itself we will undertake a review which will include significant public consultation.

### AER's assessment approach

1. The rules require us to have regard to several factors in developing and implementing a STPIS for the Victorian distributors.[[158]](#footnote-158) These include:

* Jurisdictional obligations
* consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
* ensuring that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation any regulatory obligations or requirements to which the distributor is subject.
* Benefits to consumers
* the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
* the willingness of the customer or end user to pay for improved performance in the delivery of services.
* Balanced incentives
* the past performance of the distribution network
* any other incentives available to the distributor under the rules or the relevant distribution determination
* the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
* the possible effects of the schemes on incentives for the implementation of non-network alternatives.

Our approach and reasons for developing the STPS are contained in our final decision for the national distribution STPIS.[[159]](#footnote-159)

### Reasons for AER's preliminary position

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

Jurisdictional obligations

1. In Victoria, the Electricity Distribution Code and Public Lighting Code set out GSLs that apply to the Victorian distributors.[[160]](#footnote-160) Our proposed approach to applying the STPIS in Victorian is to not create duplication or compromise the distributors' ability to comply with the jurisdictional requirements. Our proposed approach is then to not apply the GSL component of our national STPIS while the GSL arrangements in the Victorian codes remain in place. We will amend this position if the Victorian Government advises that the Victoria arrangements will cease to apply.

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.[[161]](#footnote-161)
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 unserved energy during a supply interruption. As outlined in our national STPIS, we will use VCR estimates at different stages of our annual s-factor calculation to:

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

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.[[162]](#footnote-162) The distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.

1. The AEMC recently conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.[[163]](#footnote-163) AEMO is currently reviewing current approaches to estimating VCR and will propose new VCR estimates in September 2014.
2. We will not undertake a review of our national STPIS until these studies are complete. Any change to the STPIS would be subject to the distribution consultation procedures in the rules.[[164]](#footnote-164) We consider there is insufficient time to conduct a comprehensive review of the STPIS before the Victorian distributors submit proposals for the next regulatory control period in April 2015. Therefore our preliminary approach is to apply the national STPIS in its current form and monitor ongoing work. However, if we were to amend the STPIS under a future review, it is our intention to taken into account any transitional residual incentive or penalty that applies under the current version of the STPIS in that review.

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 itself and how it interacts with our other incentive schemes.

Defining performance targets

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.[[165]](#footnote-165) Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.[[166]](#footnote-166) 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.[[167]](#footnote-167) In Victoria the STPIS will interact with our expenditure and demand management incentive schemes.
2. The 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. [[168]](#footnote-168)
3. In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[[169]](#footnote-169)
4. The 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.

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 preliminary position and reasons on how we intend to apply the EBSS to Victorian distributors in the next regulatory control period.

### ­AER's preliminary position

1. We propose applying our new EBSS[[170]](#footnote-170) to the Victorian distributors for the 2016–20 regulatory control period.
2. Our distribution determination for the Victorian 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 network users of opex efficiency gains and efficiency losses.[[171]](#footnote-171) We must also have regard to the following factors in developing and implementing the EBSS:[[172]](#footnote-172)

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

### Reasons for AER's preliminary position

1. The current EBSS applies to Victorian distributors in their current regulatory control period.[[173]](#footnote-173) 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.[[174]](#footnote-174) 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.[[175]](#footnote-175)
3. In this section we set out why we propose to apply the new EBSS to the Victorian 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.[[176]](#footnote-176) 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.[[177]](#footnote-177) 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.[[178]](#footnote-178) 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.[[179]](#footnote-179)
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.[[180]](#footnote-180) 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 1: 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. Note that as set out in table 6, the new actual of $95m is used as the forecast in the next period.
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 6 (below) provides a more detailed illustration of how the benefits are shared between distributors and consumers over time.

(Example 1 continued)

Table 6: 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 7 sums the discounted benefits to distributors and consumers from the bottom two rows of Table 6. As illustrated below, the benefits of the efficiency improvement are shared approximately 30:70 in perpetuity between the distributor and consumers.

Table 7: 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.[[181]](#footnote-181) 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. During the subsequent period when the CESS and EBSS are applied, incentives will be relatively balanced, and distributors should not have an incentive to favour opex over capex or vice versa. We discuss the CESS further in section 3.3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives:[[182]](#footnote-182)

* 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.[[183]](#footnote-183) 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.[[184]](#footnote-184)

## Capital expenditure sharing scheme

1. The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. This section sets out our preliminary position and reasons for how we intend to apply the CESS to Victorian 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.[[185]](#footnote-185) 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 preliminary position

1. Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,[[186]](#footnote-186) to the Victorian distributors in the next regulatory control period.

### AER's assessment approach

1. In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:[[187]](#footnote-187)

* make that decision in a manner that contributes to the capex incentive objective[[188]](#footnote-188)
* consider the CESS principles,[[189]](#footnote-189) capex objectives,[[190]](#footnote-190) 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 preliminary position

1. We propose to apply the CESS to the Victorian distributors in the next regulatory control period as we consider this will contribute to the capex incentive objective.
2. The Victorian 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.[[191]](#footnote-191) The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[[192]](#footnote-192) 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 the Victorian 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.[[193]](#footnote-193) 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.
7. When the CESS, EBSS and STPIS apply to distributors then incentives for opex, capex and service are balanced. This encourages distributors to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

## Demand management incentive scheme

1. This section sets out our preliminary approach and reasons for applying a demand management incentive scheme (DMIS) to the Victorian distributors in the next regulatory control period.[[194]](#footnote-194)

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.[[195]](#footnote-195) 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.[[196]](#footnote-196) To meet this requirement, and motivated by the need to improve Victorian 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 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[[197]](#footnote-197) 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. Part B is not applied where distributors are subject to a revenue cap rather than a price cap.

1. Currently both Part A and Part B of the scheme apply to the Victorian distributors because in the current regulatory control period they are subject to weighted average price cap form of control. As a revenue cap is expected to apply in the next regulatory control period, Part B will not be relevant to Victorian distributors.

### AER's preliminary position

1. Our preliminary position is to continue applying the DMIS to the Victorian distributors in the next regulatory control period.
2. We acknowledge the need to reform the existing demand management incentive arrangements. The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes[[198]](#footnote-198) proposed by the AEMC in its Power of Choice review[[199]](#footnote-199) 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 intend to 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 not indicating the allowance cap in the F&A.

### 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.[[200]](#footnote-200) These are:

* Benefits to consumers
* the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
* the 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 preliminary position

1. This section outlines the reasons for our preliminary position to apply the DMIS to Victorian 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.[[201]](#footnote-201)
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[[202]](#footnote-202) 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.[[203]](#footnote-203) We consider that a revenue cap form of control does not provide a disincentive for the Victorian 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.[[204]](#footnote-204) We consider our proposed application of the DMIS meets this requirement as 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.[[205]](#footnote-205) 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 a 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. The ability of Victorian distributors' to adopt more efficient price signals is enhanced by the now high penetration of the required metering and other enabling technologies. 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. 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.[[206]](#footnote-206) Neither our expenditure incentive schemes (EBSS and CESS) nor STPIS intend to discourage a distributor from using its DMIA allowance.

While a distributor's annual opex allowance incorporates the DMIA allowances, we may exclude the DMIA from the EBSS.[[207]](#footnote-207) 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.

## Incentive scheme benchmarks for the 2016 regulatory year

The rules provide that we are to make a preliminary determination for the Victorian distributors for the 2016–20 regulatory control period by 31 October 2015 which will take effect on 1 January 2016. We are then required to re-open the determination and make a substitute determination by 30 April 2016. The making of a substitute determination for 2016 after the year has started raises the question of which incentive scheme benchmarks / targets should be applied to the Victorian distributors in 2016.

Our preliminary position is to ultimately apply the EBSS and CESS benchmarks, and DMIA amount, as determined in our substitute determination rather than those from our preliminary determination. We consider that it is important for the incentive scheme benchmarks to reflect our ultimate decision on the efficient expenditure allowances.

1. If the expenditure scheme benchmarks[[208]](#footnote-208) increase from preliminary determination to substitute determination, then the lower benchmarks in the preliminary determination ultimately increase the incentives for the Victorian distributors to seek efficiencies. Neither the Victorian distributors nor consumers are made worse-off by updating the expenditure scheme benchmarks to reflect the ultimate (substitute ) determination.
2. If the expenditure scheme benchmarks decrease from preliminary determination to substitute determination, then there is the possibility that a Victorian distributor achieves outturn expenditure that is below the benchmark from the preliminary determination but above the benchmark from the substitute determination. In this case, the distributor is rewarded if the benchmark from the preliminary determination is retained but is penalised if the benchmark from the substitute determination is adopted.
3. Equally in this case, if the preliminary determination benchmark is retained, customers are required to fund the reward provided to the distributor despite its outturn expenditure being below the efficient level as ultimately forecast in the substitute determination. If the benchmark from the substitute determination is adopted, the distributor is penalised for outturn expenditure that may have been committed during the months in which the benchmark existing at the time would not have resulted in a penalty.
4. On balance, we consider that the factors we must consider[[209]](#footnote-209) when implementing an EBSS, CESS, or DMIS are better promoted by adopting the benchmarks from our substitute determinations. Expenditure allowances may not decrease from preliminary determination to substitute determination, and if they do the outturn expenditure of the Victorian distributors may not fall between the two allowances. In any case, the Victorian distributors are likely to have some ability to adjust expenditure programs in response to the substitute determination.

# Expenditure forecast assessment guideline

1. This attachment sets out our intention to apply our expenditure assessment guideline[[210]](#footnote-210) including the information requirements to the Victorian 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 expenditure forecast assessment guideline outlines for the 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. The Customer Challenge Panel supports this view.[[211]](#footnote-211)

We were required to develop the guideline under the rules.[[212]](#footnote-212) 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. The rules required the Victorian distributors to advise us by 31 May 2014 of the methodology they propose to use to prepare forecasts.[[213]](#footnote-213) In the F&A we must advise whether we will deviate from the guideline.[[214]](#footnote-214) This will provide clarity to the distributors on how we will apply the guideline and the information they should include in their regulatory proposals.

The expenditure assessment 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.[[215]](#footnote-215)

We developed the guideline to apply broadly to all electricity transmission and distribution businesses. However, some customisation of the data requirements contained in the expenditure assessment 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 be sufficient to scrutinise 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 Victorian distributors for the next regulatory control period. This should occur after we have finalised our decisions on classification and form of control.

# Depreciation

1. As part of the roll forward methodology, when the RAB is updated from forecast capex to actual capex at the end of a regulatory control period, it is also adjusted for depreciation. This attachment sets out our preliminary approach to calculating depreciation when the RAB is rolled forward to the commencement of the 2020–25 regulatory control period.
2. The depreciation we use to roll forward the RAB can be based on either:

* Actual capex incurred during the regulatory control period (actual depreciation). We roll forward the RAB based on actual capex less the depreciation on the actual capex incurred by the distributor; or
* The capex allowance forecast at the start of the regulatory control period (forecast depreciation). We roll forward the RAB based on actual capex less the depreciation on the forecast capex approved for the regulatory control period.

1. The choice of depreciation approach is one part of the overall capex incentive framework.
2. Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.[[216]](#footnote-216) In summary:

* If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that the RAB will increase by a lesser amount than if forecast depreciation were used. So, the distributor will earn less revenue into the future (i.e. it will bear more of the cost of the overspend into the future) than if forecast depreciation had been used to roll forward the RAB.
* If there is a capex underspend, actual depreciation will be lower than forecast depreciation. This means that the RAB will increase by a greater amount than if forecast depreciation 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 incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for shorter lived assets compared to longer lived assets. Forecast depreciation, on the other hand, leads to the same incentive for all assets.

## AER's preliminary position

1. Our preliminary position is to use the forecast depreciation approach to establish the RAB at the commencement of the 2021–25 regulatory control period for the Victorian 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.[[217]](#footnote-217)
2. We are required to set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.[[218]](#footnote-218) Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[[219]](#footnote-219)

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

## Reasons for AER's preliminary position

1. Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2021–25 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 incentives guideline.[[220]](#footnote-220)

Our approach is to apply forecast depreciation except where:

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

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

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

1. We have chosen forecast depreciation as our default approach because, in combination with the CESS, it will provide a 30 per cent reward for capex underspends and 30 per cent penalty for capex overspends, which is consistent for all asset classes. In developing our capex incentives guideline, we considered this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.
2. The opening RAB for the 2016–20 period will be established using actual depreciation, as stated in our previous determination that applies to the Victorian distributors for the 2011–15 period. The use of forecast depreciation to establish the opening RAB for the 2021–25 period will therefore represent a change of approach. Victorian distributors are not currently subject to a CESS but we propose to apply the CESS in the next regulatory control period. We discuss this further in section 3.3.
3. For Victorian 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.[[221]](#footnote-221) Therefore, we do not see the need to apply actual depreciation at this time.

# Jurisdictional and legacy issues

1. The rules do not limit the matters distributors may request the AER to amend in an F&A.[[222]](#footnote-222) Similarly, we may make an F&A that extends beyond the matters specifically listed in the rules.[[223]](#footnote-223) This attachment sets out our preliminary position on a range of matters raised by the Victorian distributors. We also address dual function assets.

## **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. None of the Victorian distributors currently own, control or operate any dual-function assets, nor did they own, control or operate any dual function assets at the time of the last determination. Therefore, our preliminary position is that we are not required to, and will not; make any determination under the rules regarding dual-function assets.[[224]](#footnote-224)

## 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.[[225]](#footnote-225) The scheme was first legislated under the Energy and Resources Legislation Amendment Act 2010 on 24 June 2010. It was implemented by adding s16C to the National Electricity (Victoria) Act 2005 (the NEVA). Section 16C provides that The Governor in Council, by Order published in the Government Gazette may confer functions and powers, or impose duties on the AER to make determinations on performance targets and incentive mechanisms for the scheme.
2. Subsequently, the Victorian Government published the f-factor scheme order 2011 (the Order) on 23 June 2011 under the NEVA. The Order prescribes that:
   * + - 1. For the first four years of the scheme (2012-15), DNSPs will be either rewarded or penalised at the pre-determined incentive rate of $25,000 per fire for performing better or worse than their respective targets. The reward/penalty amounts will apply to 2014-2016 respectively.
         2. In the current regulatory period that the reward/penalty amounts are treated as cost pass through amounts for the regulatory years that commence on 1 January 2014 and 1 January 2015. We must make f-factor amount determinations with respect to the pass through amounts for these two regulatory years, for the fire starts of 2012 and 2013 respectively.(i.e. Rewards/penalties lag the event by up to two years.)
         3. After the current regulatory control period (2011-15), we may vary the incentive rates and mechanism of the scheme, such as applying different targets for different parts of the network.

Given that we only have two years operation experience of the scheme, our preliminary position is that we will 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.

We also intend to apply to incentive mechanism in a manner similar to the other incentive schemes, such as the STPIS. Hence, we propose to add an “f-factor” adjustment amount term to 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 scheme will remain in place unless changed or discontinued by the Victorian Government, subject to any steps necessary to amend or close out the scheme.

1. Appendix A: Rule requirements for classification
2. We must have regard to four factors when classifying distribution services.[[226]](#footnote-226)
   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.[[227]](#footnote-227)
  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)[[228]](#footnote-228)
  2. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[[229]](#footnote-229)
  3. any other relevant factor.[[230]](#footnote-230)

1. The rules specify additional requirements for services we have regulated before.[[231]](#footnote-231) 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.[[232]](#footnote-232)
   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.[[233]](#footnote-233)
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.
4. Appendix B: Proposed classification of Victorian 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 - customer below 100 amps | | 1. Alternative control | 1. Alternative control (fee-based) |
| Routine connections - customers above 100 amps | | 1. Alternative control | 1. Alternative control (quoted) |
| New connections requiring augmentation | | 1. Standard control | 1. Standard control |
| Supply enhancement at customer request | | 1. Unclassified | 1. Alternative control (quoted) |
| Supply abolishment | | 1. Alternative control | 1. Alternative control (quoted) |
| Temporary disconnect/reconnect services | | 1. Alternative control | 1. Alternative control (fee-based) |
| De-energisation of existing connections | | 1. Alternative control | 1. Alternative control (fee-based) |
| Energisation of existing connections | | 1. Alternative control | 1. Alternative control (fee-based) |
| PV installation | | 1. Alternative control | 1. Alternative control (fee-based) |
| AER service group—metering services provided while AMI order in council applies | |  |  |
| Installation, operation, repair & maintenance, and replacement of type 1-4 metering installations | | 1. Unclassified | 1. Unclassified |
| Installation, operation, repair & maintenance, and replacement of type 5-6 metering installations | | 1. Unclassified | 1. Unclassified |
| Operation of type 7 metering installations | | 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 | | 1. Unclassified | 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 | | 1. Unclassified | 1. Unclassified |
| Meter exit services | | 1. Alternative control\* | 1. Unclassified |
| Meter restoration services | | 1. Alternative control\* | 1. Unclassified |
| Meter investigation | | 1. Alternative control | 1. Alternative control (fee-based) |
| Special meter read | | 1. Alternative control | 1. Alternative control (fee-based) |
| Re-test of type 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh | | 1. Alternative control | 1. Alternative control (fee-based) |
| AER service group—metering services provided after AMI order in council expires | |  |  |
| Installation, operation, repair & maintenance, and replacement of type 1-4 metering installations (excluding smart meters) | | 1. Unclassified | 1. Unclassified |
| Installation, operation, repair & maintenance, and replacement of type 5-6 and smart metering installations | | 1. Alternative control | 1. Unclassified |
| Operation of type 7 metering installations | | 1. Alternative control | 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) | | 1. Unclassified | 1. Unclassified |
| Collection of meter data, processing and storage of meter data, and provision of access to meter data for type 5-6 and smart metering installations | | 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 | 1. Alternative control (fee-based) |
| Special meter read | | 1. Alternative control | 1. Alternative control (fee-based) |
| Re-test of type 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh | | 1. Alternative control | 1. Alternative control (fee-based) |
| AER service group—public lighting services | |  |  |
| Operation, repair, replacement, and maintenance of DNSP public lighting assets | | 1. Alternative control | 1. Alternative control |
| 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 | 1. Alternative control (fee-based) |
| Wasted attendance - not DNSP fault | | 1. Alternative control | 1. Alternative control (fee-based) |
| Service truck visits | | 1. Alternative control | 1. Alternative control (fee-based) |
| Reserve feeder | | 1. Alternative control | 1. Alternative control (fee-based) |
| Temporary supply services | |  | 1. Alternative control (fee-based) |
| Rearrangement of network assets at customer request, excluding alteration and relocation of public lighting assets | | 1. Alternative control | 1. Alternative control (quoted) |
| Auditing design and construction | | 1. Alternative control | 1. Alternative control (quoted) |
| Specification and design enquiry fees | | 1. Alternative control | 1. Alternative control (quoted) |
| Elective undergrounding where above ground service currently exists | | 1. Alternative control | 1. Alternative control (quoted) |
| Damage to overhead service cables caused by high load vehicles | | 1. Alternative control | 1. Alternative control (quoted) |
| High load escorts - lifting overhead lines | | 1. Alternative control | 1. Alternative control (quoted) |
| Covering of low voltage lines for safety reasons | | 1. Alternative control | 1. Alternative control (quoted) |
| After hours truck by appointment | | 1. Alternative control | 1. Alternative control (quoted) |
| Emergency recoverable works | |  | 1. Alternative control (quoted) |
| Provision of possum guards | | 1. Unclassified | 1. Unclassified |
| Installation, repair, and maintenance of watchman lights | | 1. Unclassified | 1. Unclassified |

\* The rules state that exit and restoration fees must be classified as alternative control services. (see: NER 11.17.6(b))

1. Appendix C: Shortened forms

|  |  |
| --- | --- |
| Shortened Form | Extended Form |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| capex | capital expenditure |
| CESS | capital expenditure sharing scheme |
| CPI | consumer price index |
| CPI-X | consumer price index minus X |
| current regulatory control period | 1 January 2011 to 31 December 2015 |
| DMIA | demand management innovation allowance |
| DMIS | demand management incentive scheme |
| distributor | distribution network service provider |
| DUOS | distribution use of system |
| EBSS | efficiency benefit sharing scheme |
| expenditure assessment guideline | expenditure forecast assessment guideline for electricity distribution |
| F&A | Framework and approach |
| kWh | kilowatt hours |
| MAR | maximum allowable revenue |
| NECF | National Energy Customer Framework |
| 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 |
| NUOS | network use of system |
| opex | operating expenditure |
| RAB | regulatory asset base |
| ROLR | retailer of last resort |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |
| SCER | Standing Council on Energy and Resources |
| STPIS | service target performance incentive scheme |
| Vic | Victoria |
| WAPC | weighted average price cap |

1. NER, cl. 6.8.1(a)(2). [↑](#footnote-ref-1)
2. Responses are available at [www.aer.gov.au](http://www.aer.gov.au). CitiPower, Jemena, Powercor, SP AusNet, and United energy each provided a written request for a new F&A in accordance with NER, cl. 6.8.1(c)(1). [↑](#footnote-ref-2)
3. CitiPower & Powercor, letter to the AER, 30 January 2014. [↑](#footnote-ref-3)
4. NER, cl. 6.8.1(b)(2). [↑](#footnote-ref-4)
5. In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules. [↑](#footnote-ref-5)
6. NER, clauses 6.8.1(c)(1)–(3). [↑](#footnote-ref-6)
7. AER, Confidentiality guideline, 19 November 2013. [↑](#footnote-ref-7)
8. AER, Consumer engagement guideline for network service providers, 6 November 2013. [↑](#footnote-ref-8)
9. A distribution service is a service provided by means of, or in connection with, a distribution system. [↑](#footnote-ref-9)
10. 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-10)
11. Appendix B sets out the Victorian distributors' distribution services in more detail. [↑](#footnote-ref-11)
12. Under the AMI Order in Council, the five DNSPs must submit an estimate of costs for each year of the AMI program. These estimates are adjusted by the AER in the following year for differences between actual cost and estimated cost. [↑](#footnote-ref-12)
13. Emergency recoverable works are services related to repairing the distribution network after damage to restore or maintain electricity supply. [↑](#footnote-ref-13)
14. NER, clause 6.2.5(a). [↑](#footnote-ref-14)
15. NER, clause 6.12.3(c). [↑](#footnote-ref-15)
16. NER, clause 6.2.5(b). [↑](#footnote-ref-16)
17. NER, clause 6.2.5(b). [↑](#footnote-ref-17)
18. NER, clauses 6.2.5(c) and 6.2.5 (d). [↑](#footnote-ref-18)
19. 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-19)
20. AER, Electricity distribution network service providers, Service target performance incentive scheme, June 2008, p. 2; AER, Expenditure incentives guideline, 29 November 2013. [↑](#footnote-ref-20)
21. Electricity Distribution Code (Victoria). [↑](#footnote-ref-21)
22. NER, clause 6.6.4. [↑](#footnote-ref-22)
23. NER, clauses 6.8.1(b)(1)(ii) and 6.25(b). [↑](#footnote-ref-23)
24. Energy and Resources Legislation Amendment Bill 2010, Explanatory Memorandum, p.10. [↑](#footnote-ref-24)
25. 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-25)
26. 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-26)
27. NER, clause 6.12.3(b). [↑](#footnote-ref-27)
28. NER, chapter 10, glossary. [↑](#footnote-ref-28)
29. NER, chapter 10, glossary. [↑](#footnote-ref-29)
30. See Appendix B for a list of each distribution service falling within the groups set out above. [↑](#footnote-ref-30)
31. NER, chapter 10, 'distribution system'. [↑](#footnote-ref-31)
32. Under the AMI Order in Council, the five DNSPs must submit an estimate of costs for each year of the AMI program. These estimates are adjusted by the AER in the following year for differences between actual cost and estimated cost. [↑](#footnote-ref-32)
33. NER, clause 6.2.1(c); NEL, s. 2F. [↑](#footnote-ref-33)
34. NER, clause 6.2.1(c). [↑](#footnote-ref-34)
35. NER, clause 6.2.2(c). [↑](#footnote-ref-35)
36. NER, clause 6.2.2(d). [↑](#footnote-ref-36)
37. NER, clauses 6.2.1(d) and 6.2.2(d). [↑](#footnote-ref-37)
38. NER, chapter 10, definition of 'network service'. [↑](#footnote-ref-38)
39. Licences are issued by the Essential Services Commission of Victoria. [↑](#footnote-ref-39)
40. Under s. 88A of the Electricity Industry Act 1994 (Vic), a person must be granted either a licence or an exemption in order to distribute electricity in Victoria. [↑](#footnote-ref-40)
41. This is relevant under the form of regulation factors; see NEL, s. 2F(a). [↑](#footnote-ref-41)
42. This is a relevant form of regulation factor: NEL, s. 2F(d). [↑](#footnote-ref-42)
43. NER, clause 6.2.2(c). [↑](#footnote-ref-43)
44. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-44)
45. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-45)
46. NER, clause 6.2.2(c)(3). [↑](#footnote-ref-46)
47. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-47)
48. NER, clause 6.2.1(c)(4). [↑](#footnote-ref-48)
49. 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-49)
50. NER, chapter 10 defines connection services 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-50)
51. 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-51)
52. On the basis there is no need to regulate this service as it is covered by other services in Guideline 14. [↑](#footnote-ref-52)
53. NER, clauses 6.2.1 and 6.2.2. [↑](#footnote-ref-53)
54. Since the limit in Guideline 14 on the amount of a customer's capital contribution applies to the Victorian distributors irrespective of the AER's service classification. [↑](#footnote-ref-54)
55. The NECF is a framework for the retail sale of electricity and gas to residential and small business energy customers. It is set out in chapter 5A of the NER but does not currently apply in Victoria. The NECF includes provisions addressing customer connection services and charges, and the ACCC's connection charge guidelines were made as part of the NECF. The NECF has been adopted by the ACT, Tasmania, South Australia, and New South Wales. [↑](#footnote-ref-55)
56. SCER, National Energy Customer Framework, <http://www.scer.gov.au/workstreams/energy-market-reform/national-energy-customer-framework>, accessed 5 May 2014. [↑](#footnote-ref-56)
57. See: <http://www.aer.gov.au/node/7258> [↑](#footnote-ref-57)
58. See: <http://www.aemc.gov.au/Rule-Changes/Connecting-embedded-generators-under-Chapter-5A> [↑](#footnote-ref-58)
59. NER, chapter 6, part D. [↑](#footnote-ref-59)
60. NER, clause 6.7.5. [↑](#footnote-ref-60)
61. NER, clause 6.7.5(c). [↑](#footnote-ref-61)
62. AER, Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15, August 2008, p. 17. [↑](#footnote-ref-62)
63. Electricity Supply Act 1995 (NSW). [↑](#footnote-ref-63)
64. NEL, s. 2F(a). [↑](#footnote-ref-64)
65. NER, cl. 6.2.2(c)(5). [↑](#footnote-ref-65)
66. Section 16 of the Electricity Industry Act 2000 (Vic). [↑](#footnote-ref-66)
67. AER staff discussion with Victorian electricity distributors, May 2014 [↑](#footnote-ref-67)
68. All connections to the network must have a metering installation (NER, clause 7.3.1A(a)). [↑](#footnote-ref-68)
69. See schedule 7.2 of the NER [↑](#footnote-ref-69)
70. Such as remote load control by distributors and remote appliance control by customers. [↑](#footnote-ref-70)
71. See: <http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv> [↑](#footnote-ref-71)
72. The Victorian distributors are the ‘responsible person’ for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)). [↑](#footnote-ref-72)
73. Interval meters record electricity usage every 30 minutes. [↑](#footnote-ref-73)
74. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-74)
75. 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-75)
76. NEL, ss. 2F(a)(d). [↑](#footnote-ref-76)
77. As defined in the NER, clause 11.17.1 [↑](#footnote-ref-77)
78. 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-78)
79. NEL, s. 2F(a). [↑](#footnote-ref-79)
80. NEL, s. 2F(a). Also, NER, clause 7.2.3(a)(2) –Victorians distributors are the 'responsible person' for type 5 and 6 meter installations. [↑](#footnote-ref-80)
81. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-81)
82. NER, clause 6.2.1. [↑](#footnote-ref-82)
83. NEL, s. 2F(a). [↑](#footnote-ref-83)
84. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-84)
85. 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-85)
86. NEL, s. 2F(a) and (d). [↑](#footnote-ref-86)
87. NER, clause 6.2.2(c). [↑](#footnote-ref-87)
88. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-88)
89. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-89)
90. 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-90)
91. NER, clauses 6.2.2(c)(1) and (c)(6). [↑](#footnote-ref-91)
92. NER, clause 6.2.2(c)(6). [↑](#footnote-ref-92)
93. AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012, chapter 4. [↑](#footnote-ref-93)
94. AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012, p. 83. [↑](#footnote-ref-94)
95. See: <http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv> [↑](#footnote-ref-95)
96. This is because an equation is used to calculate type 7 metering usage. No physical meter or associated services are necessary. [↑](#footnote-ref-96)
97. NEL, s. 2F(a). [↑](#footnote-ref-97)
98. NER, clause 6.2.1(d)(1). [↑](#footnote-ref-98)
99. NEL, s. 2F(a) and (d). [↑](#footnote-ref-99)
100. NER, clause 7.2.3(a)(2). [↑](#footnote-ref-100)
101. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-101)
102. AER, Framework and approach paper for Victorian electricity distribution regulation – CitiPower, Jemena, Powercor, SP AusNet, and United Energy, 29 May 2009, p. 60. [↑](#footnote-ref-102)
103. NEL, s. 2F(a). [↑](#footnote-ref-103)
104. NEL, s. 2F(d). [↑](#footnote-ref-104)
105. NEL, s. 2F(a)(d). [↑](#footnote-ref-105)
106. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-106)
107. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-107)
108. NER, clause 6.2.2(c)(5). [↑](#footnote-ref-108)
109. That is, they own the public lighting assets, which are separately recorded in a dedicated public lighting asset base. [↑](#footnote-ref-109)
110. See: <http://www.esc.vic.gov.au/Energy/Distribution/RI_FinalPublicLightCodeFollow04ReviewNCM_Apr05> [↑](#footnote-ref-110)
111. 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-111)
112. NEL, s. 2F(d). [↑](#footnote-ref-112)
113. NEL, s. 2F(a). [↑](#footnote-ref-113)
114. NEL, s. 2F(a)(d). [↑](#footnote-ref-114)
115. NER, clause 6.2.1. [↑](#footnote-ref-115)
116. NER, clause 6.2.2(c). [↑](#footnote-ref-116)
117. NER, clause 6.2.2(c)(1). [↑](#footnote-ref-117)
118. NER, clause 6.2.2(c)(2). [↑](#footnote-ref-118)
119. NER, clause 6.2.2(c)(3) and (5). [↑](#footnote-ref-119)
120. NER, clause 6.12.3(c). [↑](#footnote-ref-120)
121. NER, clause 6.12.3(c1). [↑](#footnote-ref-121)
122. NER, clause 6.2.5(b). [↑](#footnote-ref-122)
123. NER, clause 6.2.6(a). [↑](#footnote-ref-123)
124. NER, clause 6.2.5(b). [↑](#footnote-ref-124)
125. 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-125)
126. NER, clause 6.2.6(a). [↑](#footnote-ref-126)
127. 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-127)
128. Generally peak demand is referred to as the maximum load on a section of the network over a very short time period. [↑](#footnote-ref-128)
129. NER, clause 6.2.6(b). [↑](#footnote-ref-129)
130. NER, clause 6.2.6(c). [↑](#footnote-ref-130)
131. Peak prices include peak energy, demand and capacity prices. [↑](#footnote-ref-131)
132. AER, Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019, March 2013, p. 45 [↑](#footnote-ref-132)
133. AER, Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019, March 2013, p. 45. [↑](#footnote-ref-133)
134. Letter to AER, CCP sub-panel3, 23 May 2014 [↑](#footnote-ref-134)
135. AER, Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019, March 2013, p. 45. [↑](#footnote-ref-135)
136. 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-136)
137. AER, Final distribution determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, attachments, April 2012, pp. 2–24. [↑](#footnote-ref-137)
138. AER, Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17, pp. 20–23, April 2012.

     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-138)
139. 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-139)
140. IPART, Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48, August 2001, p. 10. [↑](#footnote-ref-140)
141. 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-141)
142. NER, clause 6.8.1(b)(2)(ii). [↑](#footnote-ref-142)
143. NER, clause 6.12.3(c1). [↑](#footnote-ref-143)
144. In Victoria, the transitional period is the period between the initial determination and the substitute determination. [↑](#footnote-ref-144)
145. 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-145)
146. NER, clause 6.8.1(b)(2)(ii). [↑](#footnote-ref-146)
147. NER, clause 6.12.3(c1). [↑](#footnote-ref-147)
148. AER, Electricity distribution network service providers - service target performance incentive scheme, 1 November 2009. [↑](#footnote-ref-148)
149. Except where a jurisdictional electricity GSL requirement applies. [↑](#footnote-ref-149)
150. 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-150)
151. AER, Electricity distribution network service providers – service target performance incentive scheme, 1 November 2009, clause 2.2. [↑](#footnote-ref-151)
152. AER, Electricity distribution network service providers – service target performance incentive scheme, 1 November 2009, clauses 2.5(d) and (e). [↑](#footnote-ref-152)
153. Essential Services Commission of Victoria, Electricity Distribution Code, version 7, May 2012, p. 19; Essential Services Commission of Victoria, Public Lighting Code, April 2005, p. 3. [↑](#footnote-ref-153)
154. AEMC, Advice on linking the reliability standard and reliability settings with VCR, 29 October 2013. See: www.aemc.gov.au/Market-Reviews/Open/advice-on-linking-the-reliability-standard-and-reliability-settings-with-vcr.html [↑](#footnote-ref-154)
155. AEMC, Review on national framework for distribution reliability, 27 September 2013. [↑](#footnote-ref-155)
156. AEMC, Network reliability requirements - developing values of customer reliability, letter from SCER to AEMC (terms of reference), 21 January 2014. [↑](#footnote-ref-156)
157. 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-157)
158. NER, clause 6.6.2(b). [↑](#footnote-ref-158)
159. AER, Final decision: Electricity distribution network service providers Service target performance incentive scheme, 1 November 2009. [↑](#footnote-ref-159)
160. Essential Services Commission of Victoria, Electricity Distribution Code, version 7, May 2012, p. 19; Essential Services Commission of Victoria, Public Lighting Code, April 2005, p. 3. [↑](#footnote-ref-160)
161. NER, clause 6.6.2(b)(3)(vi). [↑](#footnote-ref-161)
162. 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-162)
163. AEMC, Draft report: Review of distribution reliability outcomes and standards, 28 November 2012. [↑](#footnote-ref-163)
164. NER, Part G. [↑](#footnote-ref-164)
165. NER, clause 6.6.2(b)(3)(iii). [↑](#footnote-ref-165)
166. Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS. [↑](#footnote-ref-166)
167. NER, clause 6.6.2(b)(3)(iv). [↑](#footnote-ref-167)
168. NER, clause 6.6.2(b)(3)(v). [↑](#footnote-ref-168)
169. Included in the distributor's approved forecast capex for the next period. [↑](#footnote-ref-169)
170. AER, Efficiency benefit sharing scheme, 29 November 2013. [↑](#footnote-ref-170)
171. NER, clause 6.5.8(a). [↑](#footnote-ref-171)
172. NER, clause 6.5.8(c). [↑](#footnote-ref-172)
173. AER, Electricity distribution network service providers, efficiency benefit sharing scheme, 26 June 2008. [↑](#footnote-ref-173)
174. 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-174)
175. AER, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013. [↑](#footnote-ref-175)
176. 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-176)
177. NER, clause 6.5.8(a). [↑](#footnote-ref-177)
178. NER, clauses 6.5.8(c)(3) and 6.5.8(a). [↑](#footnote-ref-178)
179. NER, clause 6.5.8(c)(2). [↑](#footnote-ref-179)
180. NER, clause 6.5.8(c)(1). [↑](#footnote-ref-180)
181. NER, clause 6.5.8(c)(4). [↑](#footnote-ref-181)
182. NER, clause 6.5.8(c)(5). [↑](#footnote-ref-182)
183. 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-183)
184. 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-184)
185. 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-185)
186. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 5–9. [↑](#footnote-ref-186)
187. NER, clause 6.5.8A(e). [↑](#footnote-ref-187)
188. NER, clause 6.4A(a); the capex criteria are set out in clause 6.5.7(c) of the NER. [↑](#footnote-ref-188)
189. NER, clause 6.5.8A(c). [↑](#footnote-ref-189)
190. NER, clause 6.5.7(a). [↑](#footnote-ref-190)
191. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 5–9. [↑](#footnote-ref-191)
192. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12. [↑](#footnote-ref-192)
193. 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-193)
194. 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-194)
195. 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-195)
196. NER, clause 6.6.3(a). [↑](#footnote-ref-196)
197. The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009–14 period. [↑](#footnote-ref-197)
198. 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-198)
199. AEMC, Final report, Power of choice review – giving consumers' choice in the way they use electricity, 30 November 2012. [↑](#footnote-ref-199)
200. NER, clause 6.6.3(b). [↑](#footnote-ref-200)
201. NER, clause 6.6.3(b)(1). [↑](#footnote-ref-201)
202. For example, Oakley Greenwood, Valuing reliability in the national electricity market, final report, March 2011. This report was prepared for AEMO. [↑](#footnote-ref-202)
203. NER, clause 6.6.3(b)(2). [↑](#footnote-ref-203)
204. NER, clause 6.6.3(b)(6). [↑](#footnote-ref-204)
205. NER, clause 6.6.3(b)(3). [↑](#footnote-ref-205)
206. NER, clause 6.6.3(b)(4). [↑](#footnote-ref-206)
207. 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-207)
208. Including the DMIA amount. The issues surrounding the EBSS and CESS benchmarks apply to our determination on the DMIA amount. The DMIA could be overspent or underspent, but no sharing mechanism is applied to DMIA expenditure. [↑](#footnote-ref-208)
209. NER clauses 6.5.8(c), 6.5.8A(e), and 6.6.3(b). [↑](#footnote-ref-209)
210. We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864. [↑](#footnote-ref-210)
211. Letter to the AER, CCP sub-panel 3, 23 May 2014 [↑](#footnote-ref-211)
212. NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4. [↑](#footnote-ref-212)
213. NER, clauses 6.8.1A(b)(1) and 11.60.3(c). [↑](#footnote-ref-213)
214. NER, clause 6.8.1(b)(2)(viii). [↑](#footnote-ref-214)
215. AER, Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution, 29 November 2013. [↑](#footnote-ref-215)
216. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12. [↑](#footnote-ref-216)
217. NER, clause S6.2.2B. [↑](#footnote-ref-217)
218. NER, clause 6.4A(b)(3). [↑](#footnote-ref-218)
219. NER, clause S6.2.2B. [↑](#footnote-ref-219)
220. AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12. [↑](#footnote-ref-220)
221. Our ex post capex measures are set out in the capex incentives guideline, AER capex incentives guideline, pp. 13–19; the guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective, AER capex incentives guideline, pp. 20–21. [↑](#footnote-ref-221)
222. NER, clause 6.8.1(c)(1). [↑](#footnote-ref-222)
223. NER, clause 6.8.1(g). [↑](#footnote-ref-223)
224. NER, clauses 6.8.1(b)(1)(ii) and 6.25(b). [↑](#footnote-ref-224)
225. Energy and Resources Legislation Amendment Bill 2010, Explanatory Memorandum, p.10. [↑](#footnote-ref-225)
226. NER, clause 6.2.1(c). [↑](#footnote-ref-226)
227. NEL, s. 2F. [↑](#footnote-ref-227)
228. NER, clause 6.2.1(c)(2). [↑](#footnote-ref-228)
229. NER, clause 6.2.1(c)(3). [↑](#footnote-ref-229)
230. NER, clause 6.2.1(c). [↑](#footnote-ref-230)
231. NER, clause 6.2.1(d). [↑](#footnote-ref-231)
232. NER, clause 6.2.2(c). [↑](#footnote-ref-232)
233. NER, clause 6.2.2(c). [↑](#footnote-ref-233)