Preliminary positions paper

Framework and approach for Energex and Ergon Energy

Regulatory control period commencing 1 July 2015

December 2013

AUSTRALIAN
ENERGY
REGULATOR

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Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) regarding this paper by the close of business, 19 February 2014.

Submissions should be sent electronically to: QLDelectricity2015@aer.gov.au

Alternatively, submissions can be mailed to:

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

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

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

Enquiries about this paper, or about lodging submissions, should be directed to the Network Regulation branch of the AER on (02) 9230 9133.

Contents

Shortened form

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
current regulatory control period	1 July 2010 to 30 June 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 July 2015 to 30 June 2020

NUOS	network use of system
opex	operating expenditure
Qld	Queensland
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
WAPC	weighted average price cap

About the framework and approach

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution services in Australia's national electricity market (NEM).[1] We are an independent statutory authority, funded by the Australian Government. Our powers and functions are set out in the National Electricity Law (NEL) and National Electricity Rules (the rules or NER).

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.

Energex and Ergon Energy (Qld distributors) are licensed, regulated operators of Queensland (Qld) 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 Qld electricity consumers.

We regulate a variety of services provided by the Qld 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.

In September 2013, we made a decision to review the current Qld F&A for the next regulatory control period.[2] This decision arose following consultation with stakeholders.[3] Our main reason for this decision was because of significant changes to the rules, making much of the current F&A irrelevant.

The current five year Qld distribution regulatory control period concludes on 30 June 2015. This paper sets out our preliminary positions for the F&A for the next regulatory control period from 1 July 2015 to 30 June 2020 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

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1 In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules.

2 AER, *Replacement of F&A for Queensland and South Australian electricity distribution businesses, 2-15–2020*, September 2013.

3 NER, clauses 6.8.1(c)(1)–(3).

- jurisdictional and legacy issues.

We will use the F&A process to commence discussions with the Qld distributors about the treatment of confidential information as set out in our confidentiality guideline.[4] We encourage the Qld 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.[5]

Following release of this paper, we will consult with interested parties before issuing our final F&A by 30 April 2014. Table 1 summarises the Qld distribution determination process.

Table 1: Qld distribution determination process

Step	Date
AER publishes preliminary positions F&A for Qld distributors	18 December 2013
AER to publish final F&A for Qld distributors	30 April 2014
Qld distributors submit regulatory proposals to AER	31 October 2014
Submissions on regulatory proposal close	30 January 2015**
AER to publish preliminary distribution determination (prices set here take effect from 1 July 2014)	30 April 2015*
AER hold public forum on preliminary distribution determination	May 2015**
Qld distributors to submit revised regulatory proposal to AER	12 June 2015**
Submissions on revised regulatory proposal and preliminary determination close	July 2015**
AER to publish distribution determination for regulatory control period	31 October 2015

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

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

Source: NER, chapter 6, Part E.

4 AER, *Confidentiality guideline*, 19 November 2013.

5 AER, *Consumer engagement guideline for network service providers*, 6 November 2013.

Part A: Overview

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 Qld 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 things like service quality, improvements in network reliability or efficient capital and operating expenditure
- the application of a range of expenditure forecasting expenditure tools used to test the Qld distributors' regulatory proposals
- how we will calculate depreciation of the distributors' regulatory asset base going forward.

Classification of distribution services

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.

The rules establish a limited range of service classifications, to which varying levels of economic regulation apply. When we classify services we therefore determine whether we directly control prices, become involved only to arbitrate disputes, or do not regulate at all. The classification that we apply to a distribution service also determines whether the Qld distributors recover service costs by averaging them across all customers or only charging those customers benefiting directly from specific services.

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 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[6] or services that are contestable.	We have no role in regulating these services.

Source: AER

Our preliminary view is that the classification of most distribution services will not change for the 2015–20 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. Our preliminary position is to reclassify metering services from standard control to alternative control. This will facilitate more choice for customers. We also propose classifying ancillary network services as alternative control services to create a greater focus on 'user pays' for these services.

Our Qld distribution service classifications represent our preliminary position for the next regulatory control period.

Direct control services

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.[7]

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business.[8] 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

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

[7] 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).

[8] Appendix B sets out the Qld distributors' distribution services in more detail.

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 small customer connections. These services encompass construction, maintenance and repair of the network, as well as connecting new small customers.

Alternative control services

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.

Our preliminary position is to classify metering services as alternative control because 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 smart meters) suggests unbundling these services from standard control is appropriate.

We propose to retain the current alternative control classification for large customer connections, as this is a contestable service in Queensland. 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

Negotiated distribution services are those services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services. Distributors and customers are able to negotiate services and prices according to a framework established by the rules. We are available to arbitrate if necessary.

Our preliminary position is not to classify any services provided by the Qld distributors as negotiated distribution services. However, we are interested in stakeholder feedback on whether we could classify as negotiated services large customer connections for both Qld distributors and public lighting for Energex.

Unclassified (unregulated)

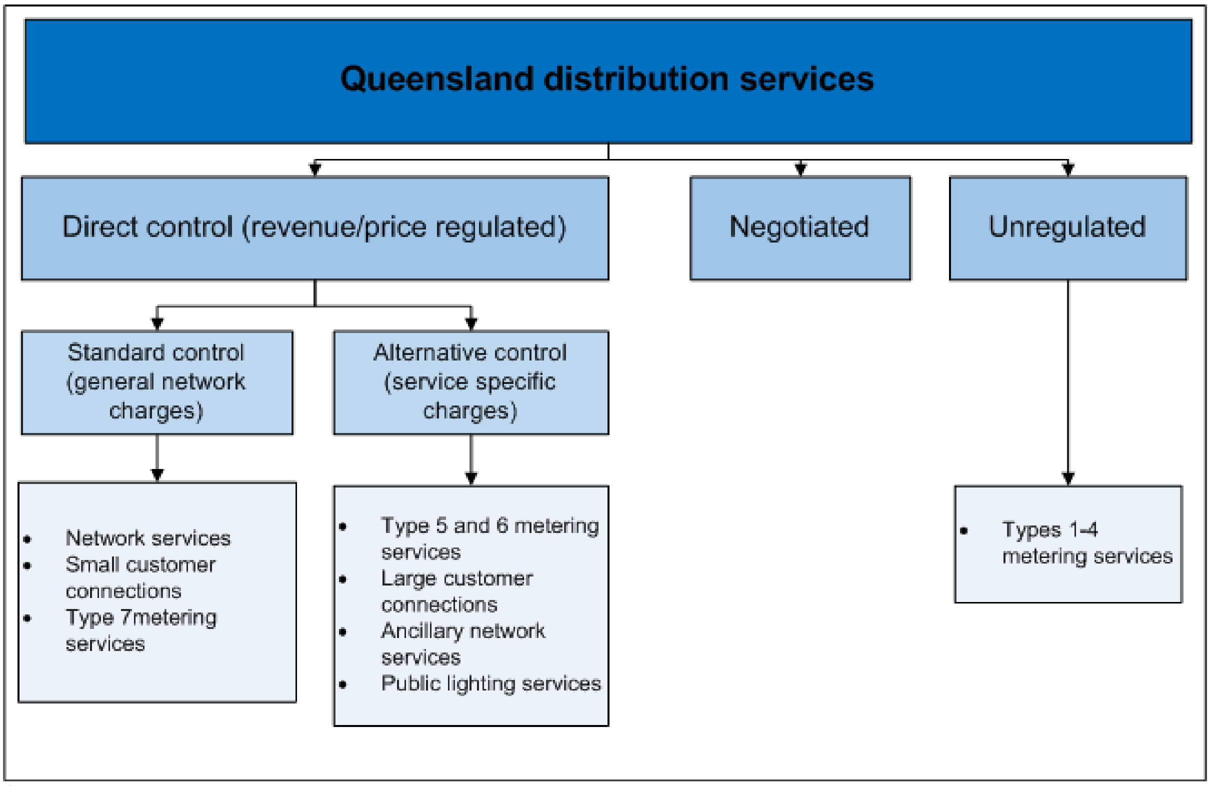
In the case of some distribution services, we may determine there is sufficient competition for no regulation at all. We will not classify such services. We refer to these as unclassified or unregulated distribution services.

Some Qld metering services are fully contestable. Our preliminary view is that consumers have sufficient capacity, within contestable markets, to negotiate efficient prices for these services effectively. Therefore we will not classify these services. This means we will have no role in the pricing of these services over the next regulatory control period.

Our preliminary position is also to not classify emergency recoverable works. 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 Qld distribution services.

Figure 1: AER preliminary position for classification of Qld distribution services



Source: AER

Control mechanisms

Following on from service classifications, our determinations must impose controls on direct control service prices and/or their revenues.[9] We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A.[10]

9 NER, clause 6.2.5(a).
10 NER, clause 6.12.3(c).

The rules require us to decide the control mechanism forms[11] 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.[12] These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

In deciding on the form of control mechanism, the rules require us to have regard to specified factors.[13] 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 Qld 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 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. Therefore our preliminary position is to retain a revenue cap for the Qld distributors' standard control services.

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

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.[14] For alternative control services, we will confirm a control mechanism basis through the distribution determination process.

Incentive schemes

The purpose of incentive schemes is to encourage distributors to manage their businesses in a safe, reliable manner that serves the long term interests of consumers. The schemes provide distributors with incentives to only incur efficient costs and to meet or exceed service quality targets. In some instances, distributors may incur a financial penalty if they fail to meet set targets. These schemes include the service target performance incentive scheme, efficiency benefit sharing scheme, capital expenditure sharing scheme and demand management incentive scheme. The overall objectives of the schemes are to:[15]

- 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)

[11] NER, clause 6.2.5(b).
[12] NER, clause 6.2.5(b).
[13] NER, clauses 6.2.5(c) and 6.2.5 (d).
[14] 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.
[15] AER, *Electricity distribution network service providers, Service target performance incentive scheme*, June 2008, p. 2; AER, *Expenditure incentives guideline*, 29 November 2013.

- share efficient improvements and losses between distributors and consumers.

We outline below our preliminary position on the application of each scheme to the Qld distributors.

Service target performance incentive scheme

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.

Our preliminary position is to continue to apply the national STPIS to the Qld distributors in the next regulatory control period. We will not apply the GSL component as the Qld distributors are subject to a jurisdictional GSL scheme.[16]

Efficiency benefit sharing scheme

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.

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 Qld distributors in the next regulatory control period.

Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

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 Qld distributors for the next regulatory control period.

Demand management incentive scheme

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).

Our preliminary position is to continue to apply the DMIS to the Qld distributors for the next regulatory control period. As we intend the Qld 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.

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16 Electricity Industry Code (Qld).

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.[17] We have not developed this scheme. Therefore, we will not be stating our preliminary position on the application of this scheme to the Qld distributors.

Application of the expenditure forecast assessment guideline

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 Qld distributors in the next regulatory control period.

The expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the Qld distributors' regulatory proposals. We intend to apply all the assessment tools set out in the guideline.

Depreciation

Changes to the rules require us to state our approach to calculating depreciation when we roll forward the Qld distributors' regulatory asset base (RAB) for the 2020–2025 regulatory control period. Our preliminary position is to use forecast depreciation to establish the RAB as at 1 July 2020.

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.

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

Ergon Energy's request

In requesting we replace the current F&A, Ergon Energy asked us to address a range of additional matters. These included regulatory issues, matters related to the end of transitional regulatory arrangements and issues relating to revenue adjustments and capital contributions.

We will address a number of Ergon Energy's issues within our distribution determination rather than as part of our F&A. For issues we can address in the F&A, we have set out our preliminary positions and reasons for our intended approach. We will address remaining issues as part of our normal consultation with the distributors, undertaken before they must submit regulatory proposals for our consideration.

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

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[17] NER, clause 6.6.4.

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

Neither Energex nor Ergon Energy currently own, control or operate any dual-function assets. This is because there is a permanent derogation in the rules in relation to the definition of 'transmission network' in Queensland.[18] Therefore, our preliminary position is that we are not required to, and will not make any determination under the rules regarding dual-function assets.[19]

[18] NER, clause. 9.32.1(b).
[19] NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

Part B: Attachments

1 Classification of distribution services

This attachment sets out our preliminary position on the classification of distribution services provided by Energex and Ergon Energy for the next regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification therefore determines whether we:

- directly control prices[20]
- 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.[21]

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 Qld 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.[22]

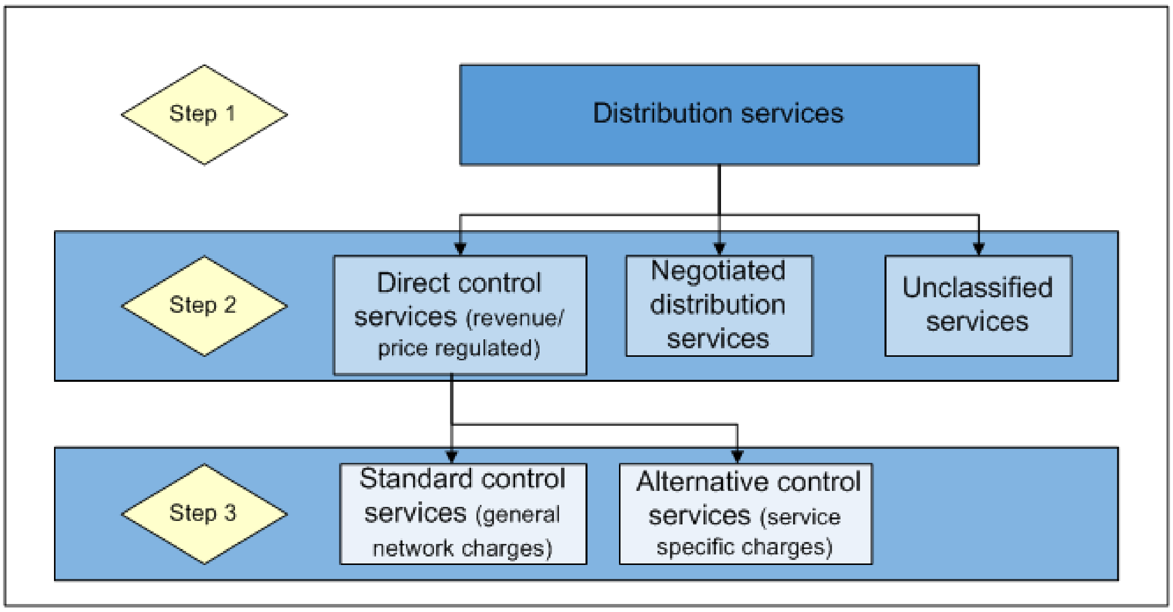
The rules set out a three step classification process we must follow. We must consider a number of specified factors at each step. Figure 2 outlines the classification process under the rules.

[20] 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.

[21] 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.

[22] NER, clause 6.12.3(b).

Figure 2: Distribution service classification process



Source: NER, chapter 6, part B.

As illustrated by figure 2 above:

- 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.[23] 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'.[24]

- 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).

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.

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:

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23 NER, chapter 10, glossary.
24 NER, chapter 10, glossary.

- 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.

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

1.1 AER's preliminary position

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 Qld distributors as:

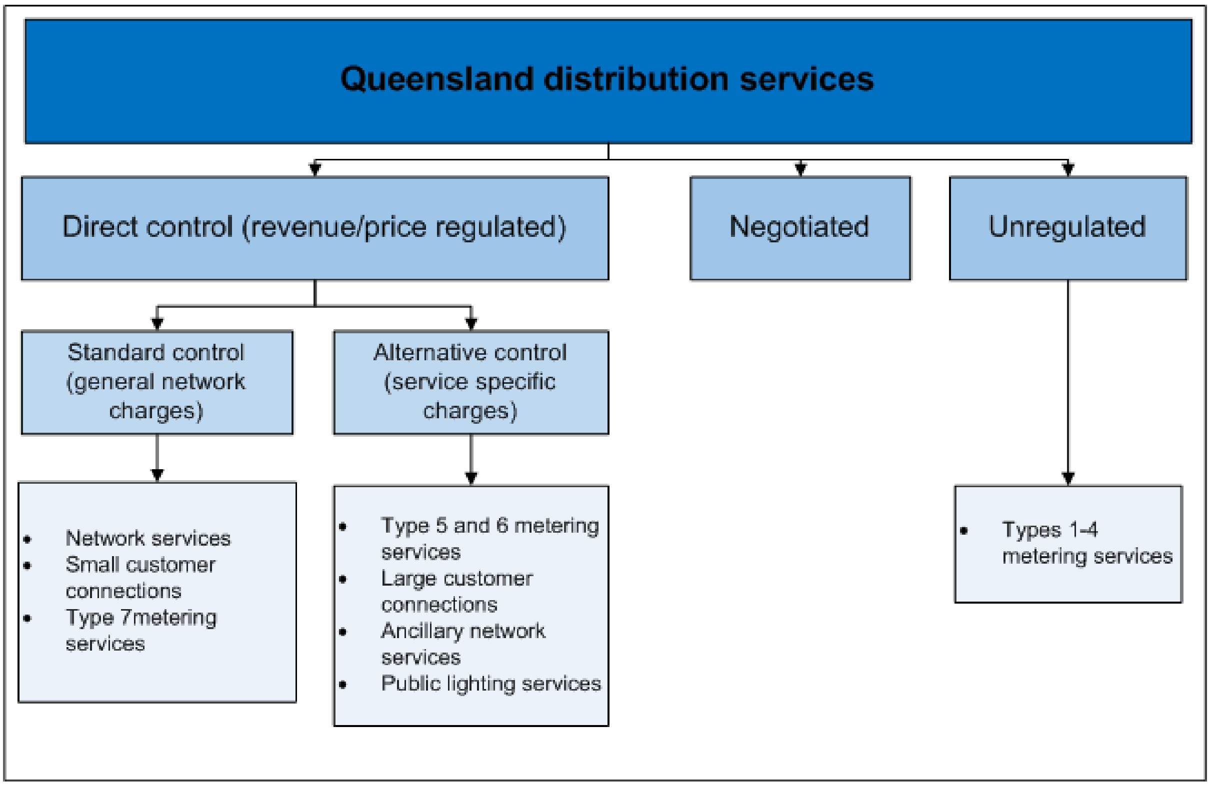
- network services
- connection services
- metering services
- ancillary network services
- public lighting services.

We consider each service falling within the above service groups is a distribution service.[25] They are services provided by means of, or in connection with, a distribution service.[26]

We propose to classify Energex and Ergon Energy's distribution services consistently. Distribution services provided by both distributors will have the same classification. Only in the case of public lighting do we think there may be different circumstances faced by Energex and Ergon Energy that could justify a different classification between the two distributors for the same service(s). Even on this issue, our preliminary approach is to classify the same service consistently and seek stakeholder views on the potential to change our approach. Figure 3 summarises our preliminary classification of the Qld distributors' distribution services. This section summarises our preliminary positions on the classification of each service group.

[25] See Appendix B for a list of each distribution service falling within the groups set out above.
[26] NER, chapter 10, 'distribution system'.

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



Source: AER

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. Energex and Ergon Energy provide network services in their respective geographic areas under exclusive distribution authorities, issued by the Qld Government. This restriction on competition exists because it would be inefficient to have more than one network in the same geographic location. Competition in the provision of network services would not be in the interests of customers because electricity prices would have to be higher, reflecting the higher costs of having to build and maintain more than one distribution network. As competition is absent, we apply the most prescriptive form of regulation to network services—direct control.

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.

Connection services relate to connecting new customers to the shared network. In Qld, we currently classify large customer connections as alternative control services and small customer connections as standard control services.[27] We propose to retain this approach. However, we could change our view on small customer connections if the Qld Government were to indicate that it would allow competition in the provision of these services.

27 Generally, small customers are those connected under the Standard Asset Connection threshold in the distributor's pricing proposal.

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. We propose to change the classification of simple type 5 (interval) and 6 (accumulation) metering services from standard control to alternative control. Doing so will mean small customers will pay for metering services they actually use. Under the current standard control classification, the metering charges customers pay may not equate to the services they use. Changing to an alternative control classification for type 5 and 6 meters will also allow customers to purchase advanced metering infrastructure (AMI), or smart meters, without paying for metering twice.

Public lighting is currently an alternative control service in Qld. Our preliminary position is to retain this classification because public lighting services are provided to specific customers—usually local government councils.

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 Qld distribution services as negotiated services. However, we are interested in stakeholder views on the possibility of classifying public lighting (for Energex only) and large customer connections as negotiated services, either now or in the future.

Finally, some distribution services are contestable. An example is the provision of smart meters, for which there are no legislative barriers to entry by third parties and alternative providers compete in a market to provide smart meters to customers. We think customers have sufficient market power to negotiate efficient prices for the provision of smart meters. We therefore propose not to classify them. This means we would continue to have no role in pricing the provision of smart meters over the next regulatory control period.

We also propose to not classify 'emergency recoverable works', though not for reasons relating to their contestability. Emergency recoverable works relate to the repair of the network after an identifiable third party has caused damage. This third party is liable at common law for the costs of repair. We consider that by not classifying this service we will establish the right incentives for distributors to recover costs from responsible parties.

1.2 AER's assessment approach

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.

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.[28] 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

28 NER, clause 6.2.1(c); NEL, s. 2F.

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.[29]

For services we intend to classify as direct control services, the rules require us to have regard to a further range of factors.[30] 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.

The rules also specify that for a service regulated previously, unless a different classification is clearly more appropriate, we must:[31]

- 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.[32]

1.3 Reasons for AER's preliminary position

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

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

1.3.1 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.[33] Customers use or rely on network services on a daily basis. Examples include the construction and maintenance of the shared network.

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.

Energex and Ergon Energy each hold the only electricity distribution authority for their respective distribution areas.[34] The *Electricity Act 1994* (Qld) prevents a person from distributing and supplying electricity unless they hold an authority permitting them to do so.[35] Additionally, customers cannot

29 NER, clause 6.2.1(c).
30 NER, clause 6.2.2(c).
31 NER, clause 6.2.2(d).
32 NER, clauses 6.2.1(d) and 6.2.2(d).
33 NER, chapter 10, definition of 'network service'.
34 Authorities are issued by the Director General of Qld's Department of Energy and Water Supply.
35 Under s. 88A of the *Electricity Act 1994* (Qld), the right to supply electricity using a supply network within a distribution area is provided under a 'distribution authority', equivalent to a licence to operate.

source network services in their district from external providers.[36] These arrangements together provide a regulatory barrier, preventing third parties from providing network services.[37] Therefore, we consider that there is no market for network services for third parties to compete in.

The Qld distributors possess significant market power due to the regulatory arrangements in place.[38] As such, we intend to classify network services as direct control services.

We must further classify direct control services as either standard or alternative control services.[39] 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.[40] The absence of competition is due to the Qld distributors holding the only authorities to provide network services in each distribution area. There would be no material effect on administrative costs for us, the Qld distributors, users or potential users.[41] This is because classifying network services as standard control services is consistent with the current regulatory approach. We currently classify network services in Qld and all other NEM jurisdictions as standard control services.[42] And finally, distributors provide network services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[43]

Emergency recoverable works

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 Qld distribution emergency recoverable works as alternative control services.

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.

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.

For this reason, we intend not to classify emergency recoverable works.[44] 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 Energex and Ergon Energy to pursue costs from parties responsible for

36 *Electricity Act 1994* (Qld), s. 41.
37 This is relevant under the form of regulation factors; see NEL, s. 2F(a).
38 This is a relevant form of regulation factor: NEL, s. 2F(d).
39 NER, clause 6.2.2(c).
40 NER, clause 6.2.2(c)(1).
41 NER, clause 6.2.2(c)(2).
42 NER, clause 6.2.2(c)(3).
43 NER, clause 6.2.2(c)(5).
44 NER, clause 6.2.1(c)(4).

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.[45]

1.3.2 Connection services

Chapter 10 of the rules defines connection services.[46] Put simply, a connection service refers to the services a distributor, or alternative service provider (ASP),[47] performs to:

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

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.

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45 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.

46 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.

47 An ASP is someone other than Ergon Energy or Energex who performs connection work when this is contestable. That is, an ASP is appointed to perform the connection work by a customer. We consider an ASP is not a contractor or other third party appointed by a distributor to perform work for which the distributor is responsible.

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

Service group	Current classification	AER preliminary classification
Small customer connections*—Design, construction, commissioning and energisation of connection assets for small customers.[48]	Standard control	Standard control
Large customer connections—Design and construction of connection assets for large customers.[49]	Alternative control	Alternative control
Commissioning and energisation of large customer connections	Standard control	Alternative control
Operate and maintain connection assets	Standard control	Standard control
Pre-connection services—general information provision	Standard control	Standard control
Pre-connection services—requested by customers or above standard requirements	Alternative control	Alternative control
Temporary connections	Alternative control	Alternative control
Connection management services (post connection)	Alternative control	Alternative control
Accreditation of alternative service providers and approval of their designs, works and materials	Standard control/ alternative control	Alternative control
* Note: A distributor may ask a small customer seeking a connection to make a further financial contribution if it expects the cost of the connection to exceed the distributor's expected regulated revenues from the connection. See Appendix B, an element of 'connection service management'—'provision of connection services above minimum requirements'.		

We consider each connection type separately below.[50]

Small customer connections

We currently classify small customer connections as direct control and standard control services. This means the cost of connecting a small customer is included in the general network charges paid by all customers. This classification reflects the Qld Government's current approach to prevent alternative service providers from providing this service. That is, only Energex and Ergon Energy may connect small customers to their networks.[51] As the Qld Government has not indicated an intention to allow competition for this service, we do not propose to change this classification. If we were to change our current approach, small customers may have to pay their connection costs up front rather than over time.[52] We think this gives additional weight to continuing the current approach.

48 Generally, small customers are those who connect under the Standard Asset Connection tariff class in the DNSP's pricing proposal.

49 Generally, large customers are those who connect under the Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) tariff classes as per the DNSP's pricing proposal.

50 NER, clauses 6.2.1 and 6.2.2.

51 NEL, s. 2F(a), (d) and (f).

52 NER, clause 6.2.1(c)(4).

Should the Qld Government indicate, before we finalise our determination, that small customer connections could become contestable before or during the next regulatory control period, we may re-consider our classification approach.[53]

We consider that the commissioning and energisation of a small customer connection is part of the connection service. Therefore, we have grouped commissioning and energisation with small customer connections and propose to classify the full service as a standard control service.

We further consider that once completed, a connection, including large customer connections, becomes part of the shared distribution network. That is, Energex and Ergon Energy 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.

Large customer connections

We currently classify large customer connections as direct control and alternative control services.[54] This is a relatively new arrangement. At the last reset, we changed the classification of large customer connections to alternative control from standard control. At the same time, the Qld Government made these services contestable.[55] We have around three years of experience with large customer connections as contestable services.

Energex and Ergon Energy have reported that alternative service providers now perform a significant number of large customer connections. The proportion varies between the distributors. Alternative service providers now perform around one third of large customer connections in Energex's distribution area. For Ergon Energy, around one quarter. The current alternative control classification and Qld Government's decision to make this service contestable seems to have been successful, though how successful is unclear.[56]

Because competition in the provision of large customer connections is still new, our preliminary position is to retain a direct control classification.[57] As the service is provided to specific customers and competition appears to be developing, we further propose to retain the current alternative control classification.[58]

We consider that the commissioning and energisation of a large customer connection is part of the service provided to a specific customer. Therefore, our preliminary position is to also classify this service as an alternative control service, consistent with the classification of large customer connections. We have classified this separately because large customer connections may be performed by alternative service providers, requiring separate commissioning and energisation by Energex or Ergon Energy.

Could large customer connections be a negotiated service?

New providers of large customer connections have entered the market and are performing some large customer connections, in competition with the distributors. While our preliminary position is to retain

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53 NER, clause 6.2.2(c)(1).
54 AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 13.
55 NEL, s. 2F(a).
56 NEL, s. 2F(d).
57 NEL, ss. 2F(a),(d) and (g).
58 NER, clause 6.2.2(c)(1)(5).

the current alternative control classification, we are interested in the possibility of moving to a more light handed approach to regulation. This could mean classifying large customer connections as negotiated services, or even not classifying them at all.

Under a negotiated classification, large customer connections would be subject to a negotiating framework set out in the rules.[59] Should negotiations fail, we are available to arbitrate. We think this 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. We also retain concerns around the current process for authorising alternative service providers for large customer connections, as discussed below.[60]

Energex and Ergon Energy themselves authorise other parties to provide these services in their respective distribution areas. That is, the distributors authorise their prospective competitors to perform large customer connections. In our last Qld distribution determination we considered this provides a limited barrier to competition.[61] As such, we were comfortable to more 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.

We can contrast the current circumstances in Qld with other states. By comparison, NSW has a well-developed independent authorisation process for accredited service providers and a competitive environment for the provision of premises connection services.[62] Moreover, in most circumstances NSW distributors do not perform connections work themselves.

In Qld, 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 Qld Government has not indicated it will establish an independent authorisation system.

Were we to classify large customer connections as negotiated services, the rules would obligate Energex and Ergon Energy to each prepare a negotiating framework.[63] 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.[64]

For the reasons set out above, we seek stakeholder submissions on reclassifying Qld large customer connections as negotiated services, or not classifying them, but otherwise propose retaining an alternative control classification.

Pre-connection services

Pre-connection services include both the provision of general information about connections to the broad customer base and services provided to specific customers on request.

Provision of general information about connections is a service provided to the broad customer base. Only the Qld distributors are able to provide these services to customers.[65] Therefore, our preliminary

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59 NER, chapter 6, part D.
60 NEL, s. 2F(d).
61 AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15, August 2008*, p. 17.
62 *Electricity Supply Act 1995* (NSW).
63 NER, clause 6.7.5.
64 NER, clause 6.7.5(c).
65 NEL, s. 2F(a).

position is to classify this as a direct control service. It would be difficult, if not impractical, for distributors to separately identify and charge specific customers benefitting from this service.[66] As such, we further propose to classify pre-connection services as standard control services. This is consistent with the current classification.

Other pre-connection services are required by specific customers. These include consultation about a potential new connection and may include the distributor undertaking site inspections. In the context of a large customer connection, the distributor may be required to assess and approve connection designs made by alternative service providers. As these services are part of a distributor's role as a monopoly service provider, our preliminary position is to classify them as direct control services.[67] Because these services may be attributable to specific customers, or prospective customers, we further propose to classify them as alternative control services.[68]

Temporary connections

Distributors provide temporary connections to specific customers on request. Examples of temporary connections 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.[69] As they are provided to specific customers, we propose to further classify temporary connections as alternative control services.[70] Our preliminary position is consistent with the current classification.

Connection management services (post connection)

In addition to the connection services discussed above, Energex and Ergon Energy provide a further range of connection related services. These include services like moving the point of attachment to the network, auditing connections after energisation or upgrading a connection from an overhead to an underground connection.[71] We have grouped these services together and named them 'connection management services'. Energex and Ergon Energy provide these services under their distribution authorities. As such, our preliminary position is to classify this service group as direct control services.[72] Because the distributors provide these services to specific customers, we further propose to classify them as alternative control services.[73]

Connection management services include network augmentation required to remove a network constraint faced by a generator. Network constraints physically limit a generator's ability to send electricity into the shared network. Generators facing network constraints may ask their distributor to enhance the distribution network in a specific region to allow it to supply electricity into the broader shared network. While distributors carry out this work on the shared network, it is undertaken to benefit a specific customer—the generator affected by the network constraint.[74] We consider it is efficient for the benefitting generator to pay the full cost of a distributor's work to remove a network constraint. Therefore, our preliminary position is to group this service with other connection related services benefitting specific customers and classify the service group as alternative control.

[66] NEL, cl. 6.2.2(c)(5).
[67] NEL, s. 2F(a).
[68] NER, cl. 6.2.2(c)(5).
[69] NEL, s. 2F(a).
[70] NER, cl. 6.2.2(c)(5).
[71] See Appendix B for a full list of services grouped as 'connection management services'.
[72] NEL, s. 2F(a).
[73] NER, clause 6.2.2(c)(5).
[74] NEL, s. 2F(a). Also, NER, cl. 6.2.2(c)(5).

Accreditation of alternative service providers and approval of their designs, works and materials

Energex and Ergon Energy undertake a range of services related to alternative service providers for large customer connections. For example, they are currently responsible for the authorisation, or accreditation, of alternative service providers to perform large customer connections for their respective networks. Also, before an alternative service provider performs large customer connection works, the distributors must approve the connection designs. And finally, once a connection has been completed the distributors must assess the works.

Our preliminary position is to group together the services performed by Energex and Ergon Energy in relation to alternative service providers for large customer connections. We further propose to classify them consistently. Only Energex and Ergon Energy may perform these services, so our preliminary position is to apply a direct control classification.[75] Because the distributors provide these services to specific customers, we further propose to classify them as alternative control services.[76]

We currently classify the accreditation of alternative service providers to perform large customer connection as a standard control service. This means the cost of this service is shared across the broad customer base. We now consider that distributors should bill the alternative service providers themselves for the cost of the accreditation process. We consider this to be consistent with a user pays approach and more efficient than the current approach. By classifying alternative service provider accreditation as an alternative control service, we will facilitate such a change.

1.3.3 Metering services

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

All electricity customers have a meter that measures the amount of electricity they use.[77] However, not all customers have the same type of meter. There are different types of meters, measuring electricity usage in different ways.

The Qld distributors are the monopoly providers of type 5[78] (interval) and 6 (accumulation) meters.[79] Households and other small customers use 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.[80]

Large customers use type 1 to 3 meters which provide a range of additional functions compared to type 5 and 6 meters. Type 1 to 3 meters are competitively available and we do not regulate them—they are unclassified. Type 4 meters or 'smart meters' are competitively available for purchase from the Qld distributors or alternative providers. These are also interval meters with a communications capability allowing distributors or a third party to read them remotely. Small customers are

75 NEL, s. 2F(a).
76 NER, clause 6.2.2(c)(5).
77 All connections to the network must have a metering installation (NER, clause 7.3.1A(a)).
78 Energex does not provide type 5 meters.
79 The Qld distributors are the ‘responsible person’ for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)).
80 Interval meters record electricity usage every 30 minutes.

increasingly seeking smart meters because they offer frequent information about usage and facilitate a range of other services.[81] This allows customers to manage their electricity use better.

The Qld distributors are the monopoly providers of type 7 metering services, which are unmetered connections (for example, public lighting connections).[82] 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.

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.

Type 5 and 6 metering services are currently bundled together and classified as standard control services. 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. We therefore propose to separate type 5 and 6 metering into the following components:

- type 5 and 6 meter installation services
- type 5 and 6 meter provision, maintenance, reading, data services.

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
Metering types 5 and 6 – standard control	The AER intends to classify type 5 & 6 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**
	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

Customers must pay for metering services, as they do for all other electricity services. At issue is whether the Qld distributors should continue to bundle the cost of type 5 to 7 metering services in

81 Such as remote load control by distributors and remote appliance control by customers.
82 NER, clause 7.2.3(a)(2).

basic electricity network charges (standard control services) as they currently do. Alternatively, whether Energex and Ergon Energy should separate, or unbundle, these charges (alternative control services). Whether the Qld distributors bundle or unbundle these charges depends on the way we classify metering services.

Type 1 to 4 metering services

Type 1 to 4 metering services are contestable in Qld and competitively available.[83] For this reason, our preliminary position is not to classify these services.[84] Consequently, we will not regulate them. This is consistent with the current regulatory approach in Qld and in other jurisdictions.[85]

Type 5 and 6 metering services

Energex and Ergon Energy and the monopoly providers of type 5 and 6 meters.[86] Therefore, we propose to retain the current direct control classification for these services.[87]

Our preliminary position is to classify type 5 and 6 metering services as alternative control, changing from the current standard control classification. As standard control services, the costs of type 5 and 6 metering services are currently included in the basic electricity network charges all customers pay. By changing the classification to alternative control, Energex and Ergon Energy would remove these meter charges, reducing standard electricity charges. However, the distributors may add a separate metering charge to customer bills. To explain why our preliminary position would benefit Qld customers more broadly, we next describe the benefits for an example customer.

Suppose a customer switches from a type 5 or 6 meter to a type 4 smart meter. The customer must pay for the new type 4 meter. However, the distributor will still charge that customer for the type 5 and 6 services that are bundled in standard electricity charges even though that customer no longer uses a type 5 or 6 meter. However, if type 5 and 6 metering services were unbundled from standard network charges and billed separately, our example customer with a new type 4 meter would pay only for that new meter and, potentially, an exit fee. An exit fee would recover from the customer any costs of the type 5 or 6 meter the distributor has not yet recovered.

Also, some customers have more than one meter. Additional meters may be for solar power units, for example. Under the current standard control classification, the total cost of type 5 and 6 metering services are averaged and billed across all network customers equally. This means Qld customers with more than one meter are currently subsidised by customers with only one. By unbundling type 5 and 6 metering from network charges, distributors may charge customers with more than one meter for the multiple meters they use. In this way, customers with only one meter would no longer subsidise customers with multiple meters.[88]

Therefore, we consider changing the classification of type 5 and 6 metering services to alternative control would have at least two benefits:

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83 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)).

84 NEL, ss. 2F(a)(d).

85 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.

86 NER, clause 7.2.3(a)(2).

87 NEL, s. 2F(a).

88 NER, clause 6.2.2(c)(5).

Remove a barrier to entry for smart meters

- Customers who choose to buy a smart meter would not have to pay an ongoing charge for a type 5 or 6 meter they no longer use. This would remove a barrier to entry for smart meters, allowing a range of customer and network benefits to be realised.[89] This proposed change in classification is consistent with the Qld Government's policy position to allow a voluntary (or discretionary) roll-out of smart meters.[90] It is also consistent with recommendations by the Australian Energy Market Commission to facilitate more flexible metering arrangements.[91]

Users pay

- Customers with more than one meter would no longer be subsidised by customers with only one. Customers would pay for the metering services they use. Those customers with multiple meters would pay for multiple meters and vice versa.

As a consequence of the second benefit listed above, customers with more than one meter will face higher metering charges than they currently pay. Setting specific metering charges equal to actual metering use would be more efficient in terms of price reflectivity and more equitable.

Overall, we consider that our preliminary position to type 5 and 6 metering services will have non-price benefits for customers. This includes promoting competition and providing customers with more information and greater choice. We discuss this further below.

We intend to classify type 7 metering services separately. We also discuss this issue in more detail below.

Meter installation services

In Qld, installation of type 5 and 6 metering is not currently contestable.[92] 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.[93]

Meter provision, maintenance, reading and data services

We propose to classify metering provision, maintenance, reading and data services 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:[94]

- There is currently a regulatory barrier to any party other than the Qld distributors providing type 5 and 6 metering provision, maintenance, reading and data services.[95] Under the rules, only the relevant distributor may install a type 5 or 6 meter in its distribution service area.[96]

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89 NER, clause 6.2.2(c)(1).
90 Queensland Government, *Queensland Government response to the interdepartmental committee on electricity sector reform*, June 2013, p. 6.
91 AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, chapter 4.
92 NEL, s. 2F(a). Also, NER, clause 7.2.3(a)(2) – Qld distributors are the 'responsible person' for type 5 and 6 meter installations.
93 NER, clause 6.2.2(c)(2).
94 NER, clause 6.2.1.
95 NEL, s. 2F(a).
96 NER, clause 7.2.3(a)(2).

- Type 5 and 6 metering services are subject to a direct form of regulation in other NEM jurisdictions.[97]
- There is competition available from type 4 meters.[98]

We must further classify type 5 and 6 meter provision, maintenance and reading services as standard or alternative control services.[99] We consider these services should be alternative control services because they are provided to specific customers[100] and there is potential for contestability in type 5 and 6 metering provision, maintenance, reading and data services in future.[101]

We recognise that the Qld distributors are currently the monopoly providers of type 5 and 6 metering services.[102] However, separating the costs of meter provision, maintenance, reading and data services from shared network charges will enhance competition should contestability for these services change.[103] If charges for these services remain bundled in distribution charges, any future changes in contestability may be far less effective.

Another relevant factor[104] 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

As set out above, we propose to unbundle type 5 and 6 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.[105] 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.

The AEMC recommended metering costs be unbundled from shared network charges.[106] 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.

Based on the analysis above, our preliminary position is that it is clearly more appropriate to classify type 5 and 6 metering provision, maintenance, reading and data services as alternative control services.

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97 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.

98 NEL, s. 2F(a) and (d).

99 NER, clause 6.2.2(c).

100 NER, clause 6.2.2(c)(5).

101 NER, clause 6.2.2(c)(1).

102 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.

103 NER, clauses 6.2.2(c)(1) and (c)(6).

104 NER, clause 6.2.2(c)(6).

105 AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, chapter 4.

106 AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, p. 83.

Type 7 metering services

A type 7 metering service is a metering installation that does not measure the flow of electricity. Examples include public lights or traffic lights. Distributors charge customers, usually councils or government agencies, for unmetered connections by estimating the usage using standard data. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation, and the light bulb wattage. As only distributors estimate usage, only they can bill customers.

Energex and Ergon Energy 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.[107] For this reason, an alternative provider has limited incentive to enter the market for the provision of type 7 metering services. The Qld distributors are already performing data management services for type 5 and 6 meters. Providing type 7 metering services is a logical extension for the Qld distributors to undertake.

We consider that there is no potential to develop competition in the provision of type 7 metering services.[108] 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.[109] Therefore, our preliminary position is to continue to classify type 7 metering services as standard control services.

Auxiliary metering services

Energex and Ergon Energy 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'.

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.[110] For example, only Energex or Ergon Energy can perform an additional meter read as the monopoly provider of type 5 and 6 meter reading services.[111] For this reason, we propose to classify auxiliary metering services as direct control services.

Having decided to apply a direct control classification, we must further classify auxiliary metering services as either standard control or alternative control. Because Qld distributors provide auxiliary metering services to specific customers, we propose to classify them as alternative control services.[112]

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.

107 This is because an equation is used to calculate type 7 metering usage. No physical meter or associated services are necessary.
108 NEL, s. 2F(a).
109 NER, clause 6.2.1(d)(1).
110 NEL, s. 2F(a) and (d).
111 NER, clause 7.2.3(a)(2).
112 NER, clause 6.2.2(c)(5).

Metering classification summary

On the basis of our above analysis, our preliminary position is to classify metering services as summarised in table 5.

Table 5: AER's preliminary position to classifying metering services

AER's preliminary position	
Service	**Preliminary classification**
Metering type 1 to 4	Unclassified
Type 5 and 6 metering services	
a. Metering installation services	Alternative control
b. Metering provision, maintenance, reading and data services	Alternative control
Metering type 7	Standard control
Auxiliary metering services	Alternative control

Source: AER

1.3.4 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'.[113]

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 temporary supply, supply enhancement or after hours service provision. Ancillary network services involve work on, or in relation to, parts of the Qld distributor's 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 Energex or Ergon Energy providing ancillary network services.[114] 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.[115] These factors contribute to our preliminary view that, like network services, Energex and Ergon Energy possess market power in providing ancillary network services.

113 AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 12.
114 NEL, s. 2F(a).
115 NEL, s. 2F(d).

Because of these barriers to competition from alternative service providers, we propose to classify ancillary network services as direct control services.[116]

Having decided to apply a direct control classification, we must further classify ancillary network services as either standard control or alternative control. We intend to classify ancillary network services as alternative control because they are attributable to individual customers.[117] 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.[118] 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.[119] 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.

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

1.3.5 Public lighting

Energex and Ergon Energy operate and maintain public lighting throughout Qld, as part of their distribution networks. 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 services. 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.[120]

We also propose 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. 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 Qld 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.

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116 NEL, s. 2F(a)(d).
117 NER, clause 6.2.2(c)(5).
118 NER, clause 6.2.2(c)(2).
119 NER, clause 6.2.2(c)(5).
120 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.

Our preliminary position is to classify public lighting (including emerging technology) as a direct control service and further, as alternative control. This is consistent with our current approach. However, we think there could be customer benefits to classifying public lighting in Energex's distribution area as a negotiated service. This section first discusses our reasons for our preliminary position to classify public lighting for Energex and Ergon Energy as alternative control. Second, we discuss why Qld public lighting may be suitable for classification as a negotiated service.

While Energex and Ergon Energy do not have a legislative monopoly over these services, a monopoly position exists to some extent.[121] This is because the Qld distributors own the majority of public lighting assets.[122] That is, other parties would need access to poles and easements for instance to hang their own public lighting assets. However, Energex and Ergon Energy own and control such supporting infrastructure. Therefore, similar to network services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to Energex and Ergon Energy.[123] Based on the above analysis, our preliminary position is to classify public lighting services, including emerging technology, as direct control services.[124] This is consistent with public lighting's current classification.

As direct control services, we must further classify public lighting services as either standard control or alternative control services.[125] Our preliminary position is to classify public lighting as an alternative control service, also consistent with its current classification. This approach provides scope for third parties and new entrants to provide public lighting services for new public lighting assets. Hence, it may encourage other potential service providers to enter the market in future.[126] There would be no material effect on administrative costs to us, Qld distributors, users or potential users, because we are retaining the current classification.[127] Energex and Ergon Energy can directly attribute the costs of providing public lighting services to a specific set of customers, such as local government councils.[128]

Could Energex's public lighting be a negotiated service?

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 Energex's 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, we consider there may be scope to allow distributors and customers to negotiate public lighting services under the framework established by the rules.

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 Energex 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 Energex's physical public lighting services (by using an ‘energy only’ service). Or they may only employ Energex to replace failed light bulbs. We consider these options could provide some countervailing power to customers and place some competitive constraint on Energex's pricing of public lighting services.

Public lighting is also an area of rapid technological innovation. Emerging technologies offer more energy efficient lighting services. When public lighting is classified as an alternative control service,

121 NEL, s. 2F(d).
122 NEL, s. 2F(a).
123 NEL, s. 2F(a)(d).
124 NER, clause 6.2.1.
125 NER, clause 6.2.2(c).
126 NER, clause 6.2.2(c)(1).
127 NER, clause 6.2.2(c)(2).
128 NER, clause 6.2.2(c)(3) and (5).

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.

We are not aware of calls from Qld local councils 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 do not propose the same for Ergon Energy's public lighting services. This is because local councils in Ergon Energy's distribution area do not pay the charges we determine for public lighting. The Qld Government prevents these costs being passed on to councils.[129] We think it would not be practicable for local councils to negotiate the cost of services they do not pay for. The Qld Government has announced that 10 per cent of the non-electricity cost of public lighting will be passed on to local councils in Ergon Energy's distribution area from 1 July 2014.[130] However, it has not announced when councils will pay the full cost of public lighting services.

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

1.4 AER's preliminary approach to service classification

In summary, we intend to group and classify Energex's and Ergon Energy's distribution services as set out in table 6. Appendix B sets out a list of the Qld distributors' distribution services and our preliminary classifications.

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129 Queensland Government, *Queensland Government response to the interdepartmental committee on electricity sector reform*, June 2013, p. 8.

130 Queensland Government, *Queensland Government response to the interdepartmental committee on electricity sector reform*, June 2013, p. 8.

Table 6: AER's preliminary approach to the classification of Qld distribution services

AER service group	Preliminary classification of distribution services	Preliminary classification of direct control services
Network services (excluding emergency recoverable works that are unclassified)	Direct control	Standard control
Connection services		
Small customer connections*	Direct control	Standard control
Large customer connections	Direct control	Alternative control
Commissioning and energisation of large customer connections	Direct control	Alternative control
Operate and maintain connection assets	Direct control	Standard control
Pre-connection services—general information provision	Direct control	Standard control
Pre-connection services—requested by customers	Direct control	Alternative control
Temporary connections	Direct control	Alternative control
Connection management services (post connection)	Direct control	Alternative control
Accreditation of alternative service providers and approval of their designs, works and materials	Direct control	Alternative control
Metering services		
Type 1 to 4	Unclassified	
Type 5 and 6	Direct control	Alternative control
Type 7	Direct control	Standard control
Auxiliary metering services	Direct control	Alternative control
Ancillary network services	Direct control	Alternative control
Public lighting services	Direct control	Alternative control

Source: AER

2 Control mechanisms

This attachment sets out our proposed form of control mechanisms to apply to the Qld distributors' direct control services for the 2015–20 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.

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 2015–20 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 Qld distribution services. Broadly, we will classify a service as a direct control service if the distributor is a natural monopoly provider of the service. Typically, we split direct control services into standard and alternative control services based on the customer base for the service. For example, if the broad customer base benefits from a service, we will classify it as a standard control service. If a distributor only provides a service to specific customers, or if there is potential for competition to develop in the provision of that service, we will classify it as an alternative control service.

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.[131] 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.[132]

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2015–20 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.

2.2 AER's assessment approach

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

- the form of the control mechanisms[133]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism[134]

The rules set out the control mechanisms that may apply to both standard and alternative control services:[135]

131 NER, clause 6.12.3(c).
132 NER, clause 6.12.3(c1).
133 NER, clause 6.2.5(b).
134 NER, clause 6.2.6(a).

- 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[136]

  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.

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135 NER, clause 6.2.5(b).

136 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.

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.

2.2.1 Standard control services

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

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.[137]

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

Broadly, we consider prices are efficient if they reflect the underlying cost of supplying distribution services and take into account customers' willingness to pay.

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.[138]

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137 NER, clause 6.2.6(a).

138 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.

- 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

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

Existing regulatory arrangements

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

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

Revenue recovery

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

Price flexibility enables distributors to restructure existing prices and/or introduce charges for new services.

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

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.[139]

2.2.2 Alternative control services

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

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

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

- 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.

We must state what the basis of the control mechanism is in our distribution determination.[140] 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.[141]

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

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.

2.3.1 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.[142] 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.

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

140 NER, clause 6.2.6(b).
141 NER, clause 6.2.6(c).
142 Peak prices include peak energy, demand and capacity prices.

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.

We consider that this incentive is unlikely to give rise to inefficient pricing for Qld 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.

To illustrate relative efficiency of different tariff structures, we have drawn a number of comparisons between the Qld distributors, under a revenue cap, and the NSW distributors which are currently under a WAPC. In general, we consider 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.[143]

Figure 4 below allows us to compare the Qld distributors under the existing revenue cap and the WAPC the NSW distributors have operated under in recent years. In reviewing the form of control in NSW[144] we found that a WAPC has not encouraged the NSW distributors to adopt efficient prices, despite theory that suggested this should be an outcome of a WAPC. From the figures below we can see that despite operating under a revenue cap, the Qld distributors have a higher proportion of revenues being raised through prices we regard as more efficient, such as fixed price components and prices for controlled loads. We conclude from this evidence that the existing revenue cap has not discouraged the adoption of more efficient tariff structures.

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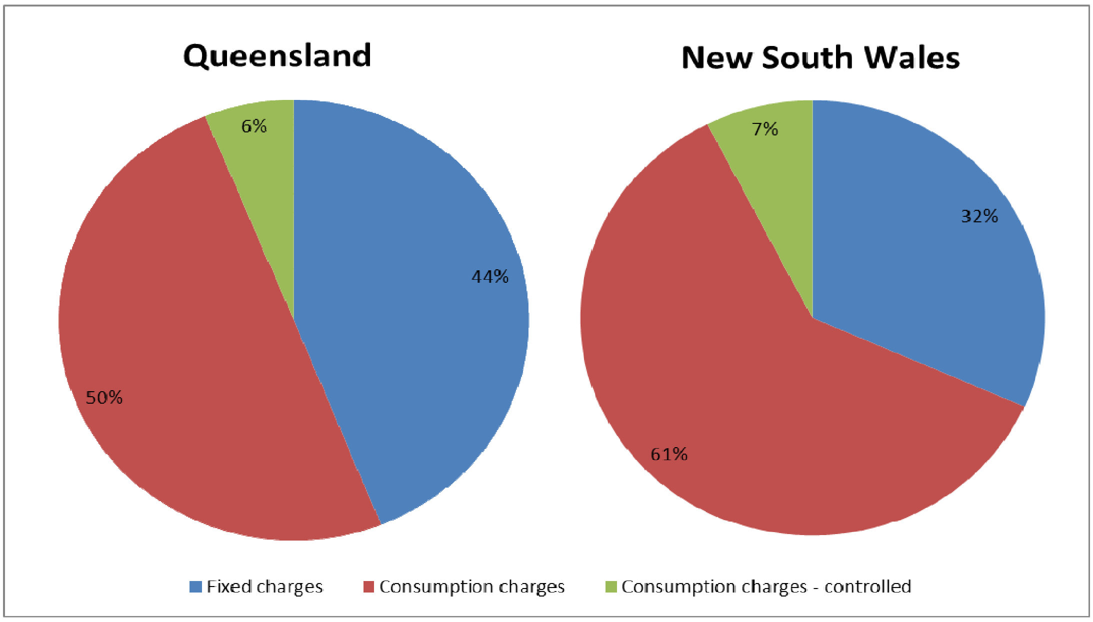
143 AER, *Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 45

144 AER, *Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 45.

Figure 4: Qld and NSW distributors' revenue type



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

2.3.2 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 WAPC would likely result in increased administrative costs in the short run. Under a WAPC revenue is variable within the regulatory control period which results in higher risk to distributors. This would likely lead to increased costs through risk minimisation strategies. Furthermore, the continuation of the revenue cap in Queensland 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.

2.3.3 Existing regulatory arrangements

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.

2.3.4 Desirability of consistency between regulatory arrangements

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.

2.3.5 Revenue recovery

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.

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.[145]

2.3.6 Pricing flexibility and stability

Pricing flexibility

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.

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. We consider that this is likely to be of increasing importance under likely changes to the pricing principles proposed by SCER.

Pricing stability

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.[146]

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,[147] we designed the unders and overs account as a rolling account with an estimate year to help smooth the price adjustments year on year.[148] We also

[145] AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 45.
[146] These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from Transmission Network Service Providers.
[147] AER, *Final distribution determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, attachments*, April 2012, pp. 2–24.
[148] AER, *Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17*, pp. 20–23, April 2012.

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.[149]

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.

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.

To illustrate price volatility, we have drawn a number of comparisons between the Qld distributors, under a revenue cap, and the NSW distributors which are currently under a WAPC.

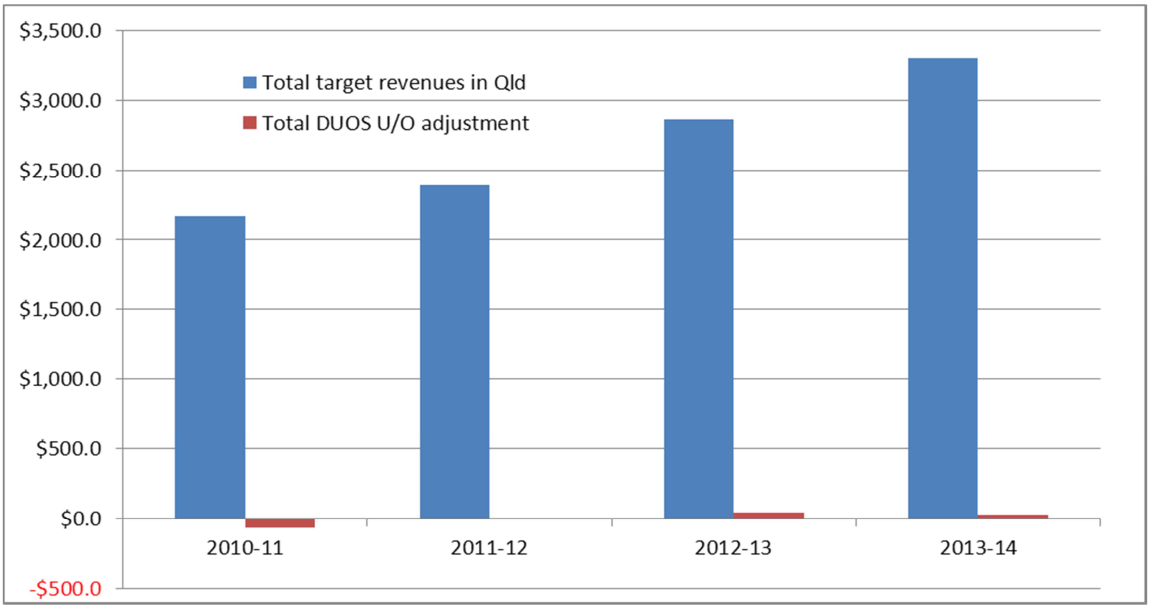
Qld electricity prices have risen sharply in recent years. For this reason, we consider that the main concern of customers is likely to be price volatility rather than changes to the distributors' revenue requirements. As the control formulae for standard control services for the current regulatory period is a revenue cap, customers may question whether the revenue cap has contributed to these sharp increases. The following explains the effect of a revenue cap amongst other factors, and resulting price changes.

A revenue cap limits the amount of revenue a distributor may raise through prices to meet its expected costs. Where prices are set too high or too low, an adjustment is required in a subsequent year to ensure the revenue is capped. This correction can only be determined after the year in question. While the annual revenue cap has been increasing in recent years, the subsequent adjustment has remained relatively small. These small overs and unders adjustments to the distribution use of service (DUOS) revenue requirements are shown in Figure 5. They have remained stable throughout the current regulatory control period.

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.

149 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.

Figure 5: DUOS unders and overs adjustments for Queensland ($ millions)



Source: AER

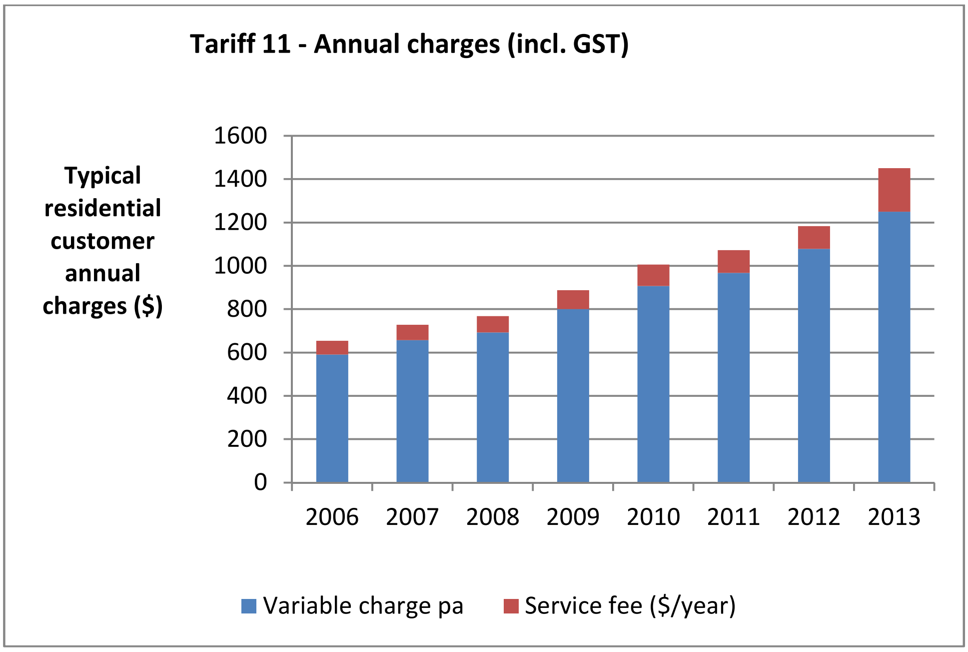
While the annual under and over adjustments have been insignificant, it is quite clear that retail electricity charges have not been stable. Factors that have contributed to steep increases in electricity prices, include:

- substantial increases in network investment that have resulted in real increases in distribution prices each year since the last determination was made. This expenditure (approved by us) was made by Qld distributors to improve service reliability, replace aging assets and cope with peak load caused by rising air conditioner use amongst other things.
- adjustments made by the Tribunal[150] to our final determination. This amounted to a change in revenue requirements in 2013–14 of 9 per cent for Energex and 7 per cent for Ergon Energy.
- adjustments to incorporate feed-in tariffs that are set by the Queensland Government and which are expected to more than double in 2014–15.

Figure 6 shows how variable and fixed electricity charges have changed for a typical residential customer since 2006. What can be seen in this figure is that while charges have risen significantly, the increases have been reasonably stable. That is, the revenue cap form of control is not causing instability. Rather, where prices have varied from year to year, this has been driven by factors like Qld Government retail pricing policies and not the revenue cap used to control distribution prices. An example of this includes the increase in the fixed 'service charge' in 2013.

150 Australian Competition Tribunal, File No 2 of 2012, 19 May 2011.

Figure 6: Typical residential customer electricity charges



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

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.

2.3.7 Incentives for demand side management

We consider a revenue cap provides an efficient incentive to undertake demand side management.

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.

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.

2.3.8 Hybrid form of control

We consider that higher administrative costs to distributors and us under a hybrid revenue cap outweigh its potential benefits.

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.[151] 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.[152]

2.3.9 Formulae for control mechanism

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for standard control services in the F&A paper.[153] 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.[154]

Below is a preliminary formulae to apply to standard control services. We consider that the formula gives effect to the revenue cap.

(1) $MAR_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t*}$ i=1,...,n and j=1,...,m and t=1,...,5

(2) $MAR_t = AR_t + I_t + T_t + B_t$

(3) $AR_t = AR_{t-1}(1+CPI_t)(1-X_t)$

Where:

MAR_t is the maximum allowable revenue in year t.

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

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

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

151 IPART, *Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48*, August 2001, p. 10.

152 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.

153 NER, clause 6.8.1(b)(2)(ii).

154 NER, clause 6.12.3(c1).

I_t is the sum of incentive scheme adjustments in year t. To be decided upon in the final decision.

T_t is the sum of transitional adjustments in year t. Likely to incorporate but not limited to adjustments from the transitional regulatory control period. To be decided upon in the final decision.

B_t 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.

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

X_t is the X-factor in year t. To be decided upon in the final decision.

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

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 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.[155] 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 Qld 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.

155 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.

2.4.1 Influence on the potential to develop competition

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

2.4.2 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 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.

2.4.3 Existing regulatory arrangements

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 standard control services. Our consideration of other factors in clause 6.2.5(d) of the rules leads us to the conclusion that the continuation of the current control formula of a revenue cap would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.

Metering services and ancillary network services

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

Public lighting

Our preliminary position to apply caps on the prices of individual services is consistent with the current regulatory arrangements in Queensland.

2.4.4 Desirability of consistency between regulatory arrangements

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.

2.4.5 Cost reflective prices

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.

2.4.6 Formulae for alternative control services

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.[156] 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.[157]

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

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:

$$\overline{p}_i^t \geq p_i^t \qquad i=1,...,n \text{ and } t=1,2,3,4$$

$$\overline{p}_i^t = \overline{p}_i^{t-1}(1+CPI_t)(1-X_i^t)+A_i^t$$

Where:

$\overline{p}_i^t$ is the cap on the price of service i in year t

p_i^t is the price of service i in year t

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

X_i^t is the X-factor for service i in year t. To be decided upon in the final decision.

A_i^t 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.

Services currently classified as standard control services which may be reclassified as alternative control services

We propose to apply the following formulae to standard control services, which we may reclassify as alternative control services. We consider that the formula gives effect to the cap on the prices of individual services:

$$\overline{p}_i^t \geq p_i^t \qquad i=1,...,n \text{ and } t=1,...,5$$

156 NER, clause 6.8.1(b)(2)(ii).
157 NER, clause 6.12.3(c1).

$$\overline{p}_i^t = \overline{p}_i^{t-1}(1+CPI_t)(1-X_i^t)+A_i^t$$

Where:

$\overline{p}_i^t$ is the cap on the price of service i in year t

p_i^t is the price of service i in year t

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

X_i^t is the X-factor for service i in year t. To be decided upon in the final decision.

A_i^t is an adjustment factor.

For clarity, the overall price of a quoted service is derived from one or more input prices. For example, a labour rate or material cost. Where this is the case, the price that relates to the input cost is substituted for the price term $\overline{p}_i^t$.

3 Incentive schemes

This attachment sets out our preliminary position on the application of a range of incentive schemes to the Qld 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.

3.1 Service target performance incentive scheme

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

Our national distribution STPIS[158] provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

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

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers[159] experiencing service below a predetermined level.[160]

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

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

159 Except where a jurisdictional electricity GSL requirement applies.

160 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.

- 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.

Distributors can propose to vary the application of the STPIS in their regulatory proposal.[161] 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.[162] A distributor proposing a delay must provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers.

Our national STPIS currently applies to the Qld distributors. The Qld distributors are currently subject to financial penalty or reward of ±2 per cent through an s-factor adjustment to revenue. The GSLs are a jurisdictional requirement, to the GSL component of the STPIS will not apply.[163]

3.1.1 AER's preliminary position

Our preliminary position is to continue to apply the national STPIS to the Qld 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.[164]
- 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) in the Qld jurisdictional distribution licence conditions
- 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.

We will not apply the GSL component if the Qld distributors are subject to a jurisdictional GSL scheme.[165]

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

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

163 AER, *Final framework and approach paper, application of schemes, Energex and Ergon Energy 2010–15*, November 2008, p. 5.

164 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

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.[166] The Australian Energy Market Operator (AEMO) is currently conducting analysis on how willing consumers are to pay for improvements in network reliability.[167] We consider there is likely to be inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for the Qld distributors.

3.1.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a STPIS for the Qld distributors.[168] 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.[169]

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165 The QCA is reviewing GSL arrangements are required by the Electricity Industry Code (Qld). The QCA's consultation process is ongoing. Material on this review is available at www.qca.org.au/electricity/service-quality/RevMinServStandLev15.php.

166 AEMC, *Review on national framework for distribution reliability*, 27 September 2013.

167 AEMO, *Value of customer reliability issues paper*, 11 March 2013; AEMC, *Advice on linking the reliability standard and reliability settings with VCR*, October 2013.

168 NER, clause 6.6.2(b).

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

3.1.3 Reasons for AER's preliminary position

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

Jurisdictional obligations

In Qld, the Queensland Competition Authority (QCA) administers and monitors compliance with the distribution licence conditions set out in the Electricity Industry Code. As required by the rules, we will consult with the QCA and the Department of Energy and Water Supply, as jurisdictional authorities, on the implementation of the STPIS[170] before finalising our distribution determination.

Our proposed approach to applying the STPIS in Qld intends to not compromise the distributors' ability to comply with jurisdictional licence obligations or create duplication by:

- not setting service performance targets lower than the minimum service requirements in the licence conditions; and
- not applying the GSL component of our national STPIS while QCA's guaranteed customer service arrangements remain in place.

Benefits to consumers

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.[171]

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.[172] The distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.

The AEMC recently conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.[173] AEMO is currently reviewing current approaches to estimating VCR and will propose new VCR estimates in March 2014.

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170 NER, clause 6.6.2(b)(1).
171 NER, clause 6.6.2(b)(3)(vi).
172 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.
173 AEMC, *Draft report: Review of distribution reliability outcomes and standards*, 28 November 2012.

We intend to undertake a review of our national STPIS once these studies are complete. Any change to the STPIS would be subject to the distribution consultation procedures in the rules.[174] We consider there is insufficient time to conduct a comprehensive review of the STPIS before the Qld distributors submit proposals for the next regulatory control period in October 2014. Therefore our preliminary approach is to apply the national STPIS in its current form and monitor ongoing work.

Balanced incentives

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

Distributor incentives under the STPIS

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

The rules require us to consider past performance of the distributor's network in developing and implementing the STPIS.[175] Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.[176] 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.

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.

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

In applying the STPIS we must consider any other incentives available to the distributor under the rules or relevant distribution determination.[177] In Qld, the STPIS will interact with our expenditure and demand management incentive schemes.

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. [178]

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[179]

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174 NER, Part G.
175 NER, clause 6.6.2(b)(3)(iii).
176 Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS.
177 NER, clause 6.6.2(b)(3)(iv).
178 NER, clause 6.6.2(b)(3)(v).
179 Included in the distributor's approved forecast capex for the next period.

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.

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.

3.2 Efficiency benefit sharing scheme

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

3.2.1 AER's preliminary position

We propose applying our new EBSS[180] to the Qld distributors for the 2015–20 regulatory control period.

Our distribution determination for Energex and Ergon Energy for the next regulatory control period will specify how we will apply the EBSS.

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing between distributors and network users of opex efficiency gains and efficiency losses.[181] We must also have regard to the following factors in developing and implementing the EBSS:[182]

- 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

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180 AER, *Efficiency benefit sharing scheme*, 29 November 2013.
181 NER, clause 6.5.8(a).
182 NER, clause 6.5.8(c).

- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

3.2.3 Reasons for AER's preliminary position

The current EBSS applies to Qld distributors in their current regulatory control period.[183] As part of our Better Regulation program we consulted on and published the new EBSS, taking into account the requirements of the rules.

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.[184] 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.[185]

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

In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.[186] This reasoning extends to the factors we must have regard to in implementing the scheme.

The EBSS must provide for a fair sharing of efficiency gains and losses.[187] 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.

Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.[188] 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.[189]

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

The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.[190] 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.

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[183] AER, *Electricity distribution network service providers, efficiency benefit sharing scheme,* 26 June 2008.

[184] 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.

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

[186] 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.

[187] NER, clause 6.5.8(a).

[188] NER, clauses 6.5.8(c)(3) and 6.5.8(a).

[189] NER, clause 6.5.8(c)(2).

[190] NER, clause 6.5.8(c)(1).

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

Assume that in the first regulatory period, a distributor's forecast opex is $100 million per annum (p.a.).

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.

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.

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.

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.

Table 7 (below) provides a more detailed illustration of how the benefits are shared between distributors and consumers over time.

(Example 1 continued)

Table 7: 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 (F_t)	100	100	100	100	100	95	95	95	95	95	95 p.a.
Actual (A_t)	100	100	100	95	95	95	95	95	95	95	95 p.a.
Underspend ($F_t – A_t = U_t$)	0	0	0	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t – U_{t–1}$)	0	0	0	5	0	0*	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					5	5	5	5	5		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (Ct)						**5**	**5**	**5**	**5**	**0**	**0 p.a.**
Benefits to distributor ($F_t – A_t + C_t$)	0	0	0	5	5	5	5	5	5	0	0 p.a.
Benefits to consumers ($F_1 – (F_t + C_t)$)	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, $I_6 = U_6 – (U_5 – U_4)$.

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

Table 8: Sharing of efficiency gains—Year 4 forecasting approach, with EBSS

	NPV of benefits of efficiency improvement[1]	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.[191] 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:[192]

- 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.[193] 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.[194]

3.3 Capital expenditure sharing scheme

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

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the distributor's share of the underspend or overspend should be.

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191 NER, clause 6.5.8(c)(4).
192 NER, clause 6.5.8(c)(5).
193 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.
194 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.

- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of the underspends or overspends.[195] We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of 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.

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,[196] to Energex and Ergon Energy in the next regulatory control period.

3.3.2 AER's assessment approach

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:[197]

- make that decision in a manner that contributes to the capex incentive objective[198]
- consider the CESS principles,[199] capex objectives,[200] other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

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

3.3.3 Reasons for AER's preliminary position

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

Qld 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.[201] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[202] We are also proposing to apply forecast depreciation, which we discuss further in attachment 5.

In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive

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195 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.

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

197 NER, clause 6.5.8A(e).

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

199 NER, clause 6.5.8A(c).

200 NER, clause 6.5.7(a).

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

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

schemes that apply to distributors including the EBSS, STPIS, and DMIS—which the Qld distributors will be subject to in the next regulatory control period.

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.

Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.[203] Because of this a distributor may choose to spend capex earlier, or on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

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

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.

3.4 Demand management incentive scheme

This section sets out our preliminary approach and reasons for applying a demand management incentive scheme (DMIS) to the Qld distributors in the next regulatory control period.[204]

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.[205] Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

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203 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.

204 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.

205 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.

The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.[206] To meet this requirement, and motivated by the need to improve Qld distributors' capability in the demand management area, we implemented a DMIS in our distribution determinations for the current regulatory period.

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[207] in the previous year, which we then assess against specific criteria.
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A for distributors under a weighted average price cap. In the current regulatory control period, Qld distributors are subject to revenue cap form of control. As the revenue cap is expected to continue in the next regulatory control period, Part B remains not relevant to Qld distributors.

Currently only Part A of the scheme applies to the Qld distributors.

3.4.1 AER's preliminary position

Our preliminary position is to continue applying the DMIS to the Qld distributors in the next regulatory control period.

We acknowledge the need to reform the existing demand management incentive arrangements in Qld. The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes[208] proposed by the AEMC in its Power of Choice review[209] 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.

3.4.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a DMIS for the Qld distributors.[210] 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.

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206 NER, clause 6.6.3(a).

207 The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009–14 period or under the D-factor scheme.

208 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.

209 AEMC, *Final report, Power of choice review – giving consumers' choice in the way they use electricity*, 30 November 2012.

210 NER, clause 6.6.3(b).

- 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.

3.4.3 Reasons for AER's preliminary position

This section outlines the reasons for our preliminary position to apply the DMIS to Qld distributors in the next regulatory control period.

Benefits to consumers

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.[211]

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.

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.

While studies[212] 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

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.

[211] NER, clause 6.6.3(b)(1).

[212] For example, Oakley Greenwood, *Valuing reliability in the national electricity market, final report*, March 2011. This report was prepared for AEMO.

Control mechanism and service classification

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.[213] We consider that a revenue cap form of control does not provide a disincentive for the Qld 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.

We are also required to consider the effect of service classification on a distributor's incentive to adopt or implement efficient embedded generator connections.[214] We consider our proposed application of the DMIS meets this requirement as Qld distributors will be under a revenue cap in the next regulatory control period.

Distributor's ability to offer efficient pricing structures

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.[215] 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.

At present, Qld distributors' ability to adopt more efficient price signals is constrained by the low 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. While the Qld Government is considering reforms to retail tariffs, 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 Qld, we must consider how it could potentially interact with our other incentive schemes.[216] 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.[217] 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.

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213 NER, clause 6.6.3(b)(2).
214 NER, clause 6.6.3(b)(6).
215 NER, clause 6.6.3(b)(3).
216 NER, clause 6.6.3(b)(4).
217 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.

4 Expenditure forecast assessment guideline

This attachment sets out our intention to apply our expenditure assessment guideline[218] including the information requirements to the Qld distributors for the 2015–20 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.

We were required to develop the guideline under the rules.[219] 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 Qld distributors to advise us by 30 November 2013 of the methodology they propose to use to prepare forecasts.[220] In the F&A we must advise whether we will deviate from the guideline.[221] 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.[222]

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 Qld distributors for the next regulatory control period. This should occur after we have finalised our decisions on classification and form of control.

218 We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.
219 NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4.
220 NER, clauses 6.8.1A(b)(1) and 11.60.3(c).
221 NER, clause 6.8.1(b)(2)(viii).
222 AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

5 Depreciation

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.

The depreciation we use to roll forward the RAB can be based on either:

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

The choice of depreciation approach is one part of the overall capex incentive framework.

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.[223] 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.

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.

5.1 AER's preliminary position

Our preliminary position is to use the forecast depreciation approach to establish the RAB at the commencement of the 2020–25 regulatory control period for Energex and Ergon Energy. We consider this approach will provide sufficient incentives for the distributors to achieve capex efficiency gains over the 2015–20 regulatory control period.

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

5.2 AER's assessment approach

We must decide at our determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.[224]

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.[225] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[226]

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

5.3 Reasons for AER's preliminary position

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

We had regard to the relevant factors in the rules in developing the approach to choosing depreciation set out in our capex incentives guideline.[227]

Our approach is to apply forecast depreciation except where:

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

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

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

We have chosen forecast depreciation as our default approach because, in combination with the CESS, 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.

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224 NER, clause S6.2.2B.
225 NER, clause 6.4A(b)(3).
226 NER, clause S6.2.2B.
227 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

Qld 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.

For Qld 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.[228] Therefore, we do not see the need to apply actual depreciation at this time.

228 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.

6 Jurisdictional and legacy issues

This attachment sets out our preliminary position on a range of matters raised by Ergon Energy. We also address dual function assets.

6.1 Ergon Energy's request

The rules do not limit the matters distributors may request the AER to amend in an F&A.[229] Similarly, we may make an F&A that extends beyond the matters specifically listed in the rules.[230]

In requesting that we replace the current F&A, Ergon Energy requested we address a range of matters that fall into three groups.[231] The first group encompasses regulatory issues that Ergon Energy is seeking guidance on, but would not normally form part of the F&A. The second group includes matters that relate to the end of transitional regulatory arrangements that form part of the current determination. The last group involves two additional matters relating to the regulatory treatment of revenue adjustments and capital contributions. Below, we list each of the matters raised by Ergon Energy.

Group 1: Regulatory issues

- negotiating framework
- Mt Isa–Cloncurry network
- asset categories and asset lives
- regulatory asset base value
- no prudency review
- cost pass throughs
- application of security of supply standards.

Group 2: Transitional issues

- treatment of capital contributions in calculating the annual revenue requirement
- treatment of solar feed in tariffs
- treatment of assets included in the regulatory asset base which provide standard control, alternative control and unregulated services under transitional arrangements
- recovery of charges for using the Cloncurry non-regulated 220kV network
- recovery of entry and exit charges for non-regulated connection points with Powerlink's transmission network.

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229 NER, clause 6.8.1(c)(1).
230 NER, clause 6.8.1(g).
231 Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013. See appendix C for a copy of Ergon Energy's request.

Group 3: Revenue issues

- revenue adjustments for the carry forward of over-recovery or under-recovery of revenue for this period
- our approach to capital contributions policy in the absence of National Energy Customer Framework (NECF) rule requirements.

6.1.1 AER's preliminary position

We propose to set out in our replacement F&A our intended approach to each of these matters as appropriate. Below, we have summarised the approach we intend to take to each issue. We discuss these in detail in the following section.

Group 1: Regulatory issues

- A negotiating framework is only required as part of the regulatory proposal if we indicate, as part of the F&A, that services will be classified as negotiated distribution services.
- The Mt Isa–Cloncurry network may be included in Ergon Energy's regulatory proposal.
- We will review asset categories and asset lives submitted with Ergon Energy's regulatory proposal; public lighting assets should be excluded from the regulatory asset base (RAB).
- We will consider Ergon Energy's RAB value as part of our distribution determination.
- Under transitional arrangements in the rules, we are not able to review the prudency of past capex in our determination for the next regulatory control period.
- We will make our decision on nominated pass through events as part of our distribution determination.
- In considering our distribution determination, we will again refer to the Queensland Government's position on security of supply issues.

Group 2: Transitional issues

- Under the rules, distributors should exclude the value of capital contributions from their RAB.
- We will consider treatment of solar feed-in tariffs as part of our distribution determination.
- Ergon Energy must allocate asset costs to service types according to an approved cost allocation method (CAM).
- Ergon Energy may include its expected costs related to the Cloncurry 220kV network and non-regulated Powerlink connections in its regulatory proposal.

Group 3: Revenue issues

- We will continue to liaise with the distributors on the existence and size of any over or under-recovery, and on how they may be managed.
- The Queensland Government has announced it will implement NECF in 2014.

6.1.2 AER's assessment approach

We recognise the need to provide Ergon Energy and Energex with an indication of our likely approach to assist them in preparing regulatory proposals. However, we will not address in detail in the F&A matters that are:

- better addressed as part of our assessment of a distributor's regulatory proposal
- not relevant to a distributor's development of its regulatory proposal
- better addressed via normal pre-lodgement processes.[232]

6.1.3 Reasons for AER's preliminary position

The reasons for our preliminary positions to addressing each of the matters identified by Ergon Energy is set out in turn in this section.

Group 1: Regulatory issues

The matters addressed in this section were discussed in the current F&A. However, the rules do not require the F&A to address them. Ergon Energy requested we again address these issues.[233] We note Ergon Energy did not provide new information or indicate its preferred approach to the matters discussed in this section. Rather, Ergon Energy simply identified these as matters we should address in our F&A. In considering these matters, we have referred to the positions Ergon Energy (and Energex where relevant) stated in the context of developing the current F&A. We note these positions are now somewhat dated, having originally been submitted in 2008.

Negotiating framework

In 2008, Ergon Energy submitted that its regulatory proposal need not include a negotiating framework where no negotiated distribution services were proposed.[234] In the current F&A we agreed that a distributor need not submit a negotiating framework if it does not provide negotiated services.[235] We further noted that we may classify services as negotiated services in our final F&A or draft determination.[236] This may be the case even if the distributor does not propose any negotiated services in its regulatory proposal. In these circumstances we will notify the distributor of the change of classification and request that it include a negotiating framework as part of its revised regulatory proposal.[237] This remains our position.

Mt Isa–Cloncurry network

Ergon Energy owns the Mt Isa–Cloncurry isolated distribution network. In 2008, Ergon Energy sought clarification on how we would treat this isolated network.[238] At the time, the Queensland Government was preparing to transfer regulatory responsibility for this network from the QCA to us.

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232 Such as our meetings with the distributors, exchanges of emails and letters.

233 NER, clause 6.8.1(c)(1); Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013.

234 Ergon Energy, *Submission to the AER in response to 'preliminary positions - framework and approach paper - application of schemes - Energex and Ergon Energy 2010-15*, August 2008, p. 20.

235 AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 48.

236 NER, clause 6.12.3(b).

237 NER, clause 6.8.2(c)(5).

238 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 14.

Regulatory responsibility for the Mt Isa–Cloncurry network has now transferred to us. Therefore, Ergon Energy may include this isolated network in its regulatory proposal.[239] We will assess this element of Ergon Energy's regulatory proposal, as part of our distribution determination process, under the relevant provisions of the rules.

Asset categories, asset lives and asset tax lives

In 2008, Ergon Energy sought confirmation from us that it may use in its then upcoming regulatory proposal the same asset categories it previously reported to the QCA.[240] Ergon Energy also sought confirmation that:

- public lighting assets would not be included in its regulatory asset base if they do not provide standard control services
- asset lives and asset tax lives would be treated in a particular way.[241]

Asset values are a key determinant of a distributor's revenues, as set out in our distribution determinations. In turn, the assumed 'life' of an asset is an aspect of determining its value. Similarly, asset tax lives are an aspect of determining a distributor's tax liability. We think the issues raised by Ergon Energy in 2008 were resolved in the context of our last Ergon Energy determination. To the extent Ergon Energy requires further comment, we discuss these issues again below.

Consistent with our response to these issues set out in the current F&A, we do not consider it would be appropriate for us to commit to an approach to determining asset values outside the distribution determination process.[242] We will review Ergon Energy's asset categories and remaining asset lives when making our distribution determination, in consultation with stakeholders. We expect Ergon Energy to submit a completed roll forward model and a post-tax revenue model as required under the rules.[243] We expect Ergon Energy to explain any deviations from asset classes and asset lives used for these models in our last determination.

On public lighting, we again confirm that a distributor's RAB should include only assets that provide standard control services. We currently classify Ergon Energy's public lighting services as alternative control services. Our preliminary position, set out in this paper, is to maintain Ergon Energy's public lighting services as alternative control services.

Regulatory asset base value

In 2008, Ergon Energy asked us to approve its proposed adjustments to its RAB value.[244] At that time, Ergon Energy proposed a 2005 RAB value slightly lower than had previously been calculated. The proposed adjustment included two elements. First, an increase in RAB value of $34.2 million ($July 2005) to reflect actual capex in the final year of the previous regulatory period. Second, a decrease in RAB value of $39 million ($July 2005), reflecting our acceptance of capital allowances instead of the QCA's use of inventory value.

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239 Section 10, *Electricity National Scheme (Queensland) Act 1997*.

240 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 14.

241 Ergon Energy's 2008 submission set out a propose approach to the treatment of asset lives.

242 AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 50.

243 NER, clause 6.8.2.

244 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 13.

Our current F&A sets out our decision to accept part of Ergon Energy's proposed adjustments and to consider the remaining part within our 2010 distribution determination.[245] Ergon Energy has not proposed a similar adjustment for us to address in our next F&A. We will consider Ergon Energy's RAB value as part of our distribution determination.

Prudency review

In 2008, Ergon Energy submitted that the rules do not provide for us to review the prudency of its capital expenditure during the 2005–10 regulatory control period.[246] At that time, we were not able to adjust a distributor's future RAB value in response to our assessment of the prudency of past capex. The rules have now changed to allow us to adjust a distributor's RAB in response to the prudency of a distributor's past capex.[247] However, this is not relevant to our next distribution determination. Transitional provisions prevent us adjusting a distributor's RAB for the prudency of capex incurred in or before the transitional regulatory period—Ergon Energy's current regulatory control period.[248] So, under the rules, we are not able to adjust Ergon Energy's RAB for the prudency of its past capex until its 2015-20 distribution determination.

For the distribution determination to which this preliminary F&A relates, the position stated in the current F&A remains relevant. That is, we will review past capex (and opex) to inform our decision on the forecast capex (and opex) to apply in the next regulatory control period.

Cost pass throughs

In 2008, Ergon Energy and Energex sought confirmation that they could nominate significant input cost variations as pass through events in their regulatory proposals.[249] Under the rules, distributors may submit for our approval proposals to increase the revenues they recover from consumers in response to significant cost increases in pre-approved categories. We determine the acceptable categories of pass through as part of our distribution determinations.

In response to Ergon Energy's 2008 request, the current F&A states we will consider the inclusion of additional pass through events as part of our distribution determination.[250] It further states that we think it inappropriate to indicate our likely approach outside of the distribution determination process. We maintain this position. We will make our decision on nominated pass through events as part of our distribution determination, after assessing regulatory proposals and stakeholder submissions.

Ergon Energy and Energex also sought, in 2008, confirmation of our approach to assessing the materiality of cost pass through events. The current F&A states that we considered it unnecessary to indicate our likely approach in the F&A.[251] We note that the revised rules now define as material an event that:[252]

> …results in a Distribution Network Service Provider incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the Distribution Network Service Provider has

245 AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 53.

246 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 14.

247 NER, clause S6.2.2A(f).

248 NER, clause 11.56.5.

249 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 16.

250 AER, *Final framework and approach paper - application of schemes – Energex and Ergon Energy 2010-15*, November 2008, p. 54.

251 AER, *Final framework and approach paper - application of schemes – Energex and Ergon Energy 2010-15*, November 2008, p. 55.

252 NER, Glossary.

> incurred and is likely to incur in any regulatory year of a regulatory control period, as a result of that event, exceeds 1% of the annual revenue requirement for the Distribution Network Service Provider for that regulatory year.

Ergon Energy and Energex in 2008 further sought confirmation from us that cost pass through events could apply to alternative control services in addition to standard control services.[253] The current F&A states that this forms part of our distribution determinations.[254] That is, if distributors propose pass throughs related to alternative control services, we will assess such proposals as part of our distribution determination. This remains our position.

Application of security of supply standards

In 2008, Ergon Energy and Energex sought our confirmation that the relevant security of supply standards were those approved by the Queensland Government in its:[255]

- Electricity Distribution and Service Delivery review recommendations
- the associated Queensland Government action plan.
- The current F&A states that a distributor's required expenditure should achieve compliance with all applicable regulatory obligations or requirements.[256] Further, we stated that we would be guided by the Queensland Department of Mines and Energy's position (as it was named at the time) on the security of supply standards applicable to the distributors.
- In considering our distribution determination for the next regulatory control period, we will again refer to the Queensland Government's position on security of supply issues. We note that the relevant Queensland Government agency is now the Department of Energy and Water Supply (DEWS). We have begun to liaise with DEWS on the upcoming Queensland distribution determination process. We will continue to liaise on relevant issues.

Group 2: Transitional issues

Under transitional arrangements set out in the NER, we retained the previous jurisdictional regulator's approaches to some issues.[257] Hence, some arrangements applied by the QCA continue to apply to Ergon Energy and Energex during the current regulatory control period. However, these transitional arrangements will terminate at the end of the current regulatory control period.

Ergon Energy and Energex's regulatory proposals for the next regulatory control period should not reflect the transitional provisions currently in effect. Rather, the distributor's regulatory proposals should reflect the relevant rules. Ergon Energy requested we address three issues it describes as related to the end of the current transitional arrangements. We address these issues below.

Treatment of capital contributions in calculating the annual revenue requirement

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253 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 18.

254 AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 56.

255 Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010-15*, August 2008, p. 19.

256 AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 57.

257 NER, clause 11.16.

- Ergon Energy requested we clarify our approach to the treatment of consumer (or capital) contributions in calculating its annual revenue requirement.[258] Electricity consumers make capital contributions when the expected costs of connection works are larger than the expected regulated returns to the relevant distributor. For these connection projects to proceed, distributors may ask consumers to pay a capital contribution to make up the difference between expected costs and regulated revenues.

- Under transitional arrangements, the treatment of capital contributions to Energex and Ergon Energy currently reflects the QCA's approach rather than the approach applicable under the rules. Under the QCA's approach, Energex and Ergon Energy added the value of forecast capital contributions into their RAB. To offset these additions, paid for by consumers, we made revenue reductions of equal value to the distributor's forecast regulated revenues. An annual overs and unders adjustment was made for any difference between the forecast and actual capital contributions.

- With the end of the transitional arrangements, Energex and Ergon Energy's current approach to capital contributions will no longer be consistent with the regulatory framework. For the next regulatory control period, the distributor's capital contributions policies should be consistent with the rules. Under the rules, a distributor should exclude the value of capital contributions from its RAB.[259] In discussions with the Queensland distributors, we indicated that we expect them to exclude forecast capital contributions from the RAB (consistent with other NEM jurisdictions) for the next regulatory control period.

Treatment of solar feed-in tariffs

Ergon Energy asked us to address the treatment of its recovery of costs related to Queensland's solar feed-in tariff.

Ergon Energy and Energex meet the cost incurred by retailers in paying a feed-in tariff to consumers with photovoltaic cells (solar panels) under Queensland jurisdictional arrangements. The arrangements allow distributors to recover the cost of the feed-in tariff through their network charges. Our distribution determination will address the feed-in tariff costs Ergon Energy and Energex are expected to incur in the next regulatory control period.

We understand Ergon Energy's request for us to address feed-in tariffs in the F&A relates to the potential spike in feed-in tariff costs early in the next regulatory control period. That is, actual feed-in tariff costs have been higher than estimated at the last Queensland distribution determination. The shortfall is corrected through an annual pass through allowance determined at the time of pricing approvals. However, the pass throughs are lagged by two years. This is because the actual feed-in tariff costs are not known until after the year in which they are incurred and can only be returned the subsequent year. In the first two years of the next regulatory control period, there will be an overlapping period where the historical pass through adjustment coincides with the introduction of more realistic feed-in tariff estimates for the next regulatory control period. The overlap will result in a significant increase in feed-in tariff related costs early in the next regulatory control period.

- We may smooth year to year spikes in revenue requirements, subject to restrictions established by the rules. We have already indicated to the distributors our willingness to minimise adverse consumer impacts related to these specific items. However, until we know all of the costs of a

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[258] A service provider's annual revenue requirement is the revenue we determine it will earn in a given regulatory year from charging for standard control services.

[259] NER, clause 6.21.2(1).

regulatory proposal, we do not know the extent of any possible price smoothing. We will consider this issue as part of our distribution determination, which will also provide scope for stakeholder input.

Assets providing standard control, alternative control and unregulated services under transitional arrangements

Ergon Energy requested we clarify the treatment of assets used to provide standard control, alternative control and unregulated services under transitional arrangements.[260] Under the previous Queensland jurisdictional arrangements, Ergon Energy and Energex recorded all of their assets in their RAB. When distributors used some of those assets to provide services other than standard control services, the additional revenues earned were subtracted from their approved regulated revenues. This prevented the distributors from recovering asset costs more than once. Under the transitional arrangements, this process has continued throughout the current regulatory control period.[261]

When the transitional arrangements end, the current approach to the RAB will no longer be consistent with the regulatory framework. Ergon Energy and Energex will be required to manage their RAB consistent with rule requirements. Under the rules, when an asset is established (purchased or constructed) the distributor should allocate its cost to the different types of services it provides—standard control, alternative control, negotiated or unregulated services.[262] This cost allocation is done on the basis of the asset's expected future use to provide the different types of services. Only those asset costs allocated to standard control services may be included in the RAB.[263] This cost allocation process is undertaken by each distributor according to its own cost allocation method (CAM)—a set of principles or policies, approved by us, describing how it will allocate costs to service types.[264]

To establish their respective RABs for the next regulatory control period, Ergon Energy and Energex must allocate their asset costs to service types according to an approved CAM.[265] Because their current CAMs are consistent with the previous Queensland jurisdictional approach, we expect they will each submit a revised CAM to us for approval under the relevant NER provisions. An audit process will then verify that the RAB proposed by each distributor with its regulatory proposal has been established in accordance with its CAM.

Recovery of charges for using the 220kV Cloncurry network

and

Recovery of entry and exit charges for non-regulated connection points with Powerlink's transmission network

Ergon Energy asked us to address its recovery of costs from using the non-regulated 220kV network supplying the Cloncurry Township.[266] Also, its recovery of entry and exit charges for its four non-regulated links with Powerlink's high voltage transmission network.[267]

260 Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013.
261 NER, clause 11.16.3.
262 NER, Chapter 6, Part F.
263 NER, clause 6.5.1.
264 NER, clause 6.15.1.
265 NER, Chapter 6, Part F.
266 Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013.

Under the current transitional arrangements, Ergon Energy recovers these costs by including them in its annual pricing proposal to us.[268] Therefore, they were not dealt with as part of Ergon Energy's last distribution determination. Rather, we assess Ergon Energy's proposed costs for these matters annually. The costs we approve are then added to the charges levied by Ergon Energy, which we also approve, for standard control services. Because the transitional arrangements terminate at the end of the current regulatory period, in the next regulatory control period Ergon Energy's approach to recovering these costs should be consistent with the relevant rules.

Under the rules, Ergon Energy may include its expected costs related to the Cloncurry 220kV network and non-regulated Powerlink connections in its regulatory proposal for the next regulatory control period. We would then consider them as part of our distribution determination process. Subject to our approval, Ergon Energy would then recover the approved costs for these matters in its charges for standard control services without us assessing them again.

Group 3: Revenue issues

Revenue adjustments for the carry forward of over-recovery or under-recovery of revenue

With its request that we replace the current F&A, Ergon Energy proposed we engage with it and Energex on how any over or under recovery of revenues from the current regulatory control period may be carried forward to the next. We have begun discussions with Ergon Energy and Energex on this issue. We will continue to liaise with the distributors on the existence and size of any over or under-recovery and how to manage them for the next regulatory control period. As this is an issue relevant to our distribution determination, we propose not to address this in the F&A.

Capital contributions policy in the absence of NECF rule requirements

With its request we replace the current F&A, Ergon Energy included:

> In the absence of National Energy Customer Framework rules applying to Ergon Energy in the next regulatory control period, we believe there may be benefit in engaging with stakeholders on how capital contributions arrangements will be applied in the next regulatory control period.

The NECF is a nationally consistent framework to regulate the retail supply and sale of electricity and gas. The framework intends to reduce regulatory costs, lower jurisdictional barriers and foster increased competition by creating a single national retail energy market. The NECF reforms incorporate standardised arrangements for new connections. These include a framework for distributors to request capital contributions from consumers.

Having cooperatively oversighted the development of NECF, the Australian states and territories must decide individually to adopt it.[269] The Queensland Government has announced it will implement NECF from early to mid-2014, subject to agreeing to Queensland specific variations.[270] The Queensland Government has previously indicated it sought variations to the NECF connections arrangements.

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267 Entry and exit fees relate to services provided to Ergon Energy, by Powerlink, for electricity flows between the two networks.

268 NER, clause 11.16.9.

269 South Australian legislation, including *The National Energy Retail Law (South Australia) Act 2011*, establishes the NECF reforms. To implement NECF, other states and territories must pass their own Application Act to recognise the South Australian legislation. Such enabling legislation made by other states and territories may exclude or vary elements of the South Australian legislation.

270 Queensland Government, *Queensland Government response to the Interdepartmental Committee on Electricity Sector Reform*, June 2013, p. 10.

However, those were in the context of an earlier plan to adopt much of NECF in 2012.[271] The proposed connections variations largely related to postponing the Queensland implementation to coincide with the next regulatory control period for Ergon Energy and Energex—beginning in 2014.

Ergon Energy sought clarification on our approach to capital contributions should NECF not apply to it in the next regulatory control period. The Queensland Government's position is to implement NECF in 2014. We are monitoring this matter and liaising with the Queensland Government on its NECF implementation.

6.2 Dual function assets

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

The treatment of dual-function assets is not a feature of the current Qld distribution determination or F&A. This is because neither of the distributors owned, controlled or operated dual-function assets at the time of the last determination.

Neither Energex nor Ergon Energy currently own, control or operate any dual-function assets. This is because there is a permanent derogation in the rules in relation to the definition of 'transmission network' in Queensland.[272]

Therefore, our preliminary position is that we are not required to, and will not; make any determination under the rules regarding dual-function assets.[273]

271 Queensland Government, *National Energy Customer Framework – Queensland implementation decision paper*, March 2011, p. 6.

272 NER, clause 9.32.1(b).

273 NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[274]

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.[275]

2. the form of regulation (if any) previously applicable to the relevant service or services, and, in particular, any previous classification under the present system of classification or under the present regulatory system (as the case requires)[276]

3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[277]

4. any other relevant factor.[278]

The rules specify additional requirements for services we have regulated before.[279] 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.

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274 NER, clause 6.2.1(c).
275 NEL, s. 2F.
276 NER, clause 6.2.1(c)(2).
277 NER, clause 6.2.1(c)(3).
278 NER, clause 6.2.1(c).
279 NER, clause 6.2.1(d).

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[280]

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.[281]

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.

[280] NER, clause 6.2.2(c).
[281] NER, clause 6.2.2(c).

Appendix B: Proposed classification of Qld distributors' distribution services

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
AER service group—network services			
Planning the network	Network asset – assessment of asset requirements involving investment, management and delivery including risk and feasibility assessment and estimating and cost planning Demand management - the identification and development of non-network options to address forecast network limitations. Network forecasting – analysis of network demand to enable the development of the capital program of works Network business strategy development - strategic initiatives development and management including business improvement/efficiency initiatives Governance - developing policies, procedures and standards Regulatory planning as required by the National Electricity Rules	Standard control	Standard control
Designing the network	Creation of a plan or the standards and criteria for network construction. Includes developing design standards, protection engineering and designs for augmentation and extensions to the shared network.	Standard control	Standard control
Constructing the network	Network construction, augmenting the shared network and extensions of shared network. Project planning and works management (works program development, procurement, vendor management, contract management, work scheduling and dispatching) Management of environmental issues Asset deployment and commissioning of shared network assets Asset relocation (other than those undertaken at a customer’s request)	Standard control	Standard control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
Maintaining the network	Planned maintenance – activities carried out to reduce the probability of failure or performance degradation of a network asset Corrective – activities undertaken to detect, isolate and rectify a fault so that the failed equipment, machine or system can be restored to normal operable state Work to restore a failed component of the distribution system to an operational state	Standard control	Standard control
Operating the network	Network control and operation Outage management Emergency management and response Field operations Switching and testing for network purposes Scheduling and controlling the switching of controllable load for network purposes	Standard control	Standard control
Administrative support for provision of network services	Customer interactions including network product development, customer service management/call centre, complaints and enquiries, record management and network claim processing. Market operations: includes revenue management, network billing, processing of service order requests, market notifications of retailer changes. National Metering Identifier (NMI) establishment, discovery requests and classification in accordance with the rules. Populate and maintain NMI standing data in Market Settlement and Transfer Solution in accordance with the rules. Processing and publication of notifications of new connections and alterations. Pricing strategy and development of pricing proposals. Financial and commercial management Compliance monitoring and reporting. Procurement activities.	Standard control	Standard control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	Technical and safety training of DNSP staff. Supply, manage and maintain DNSP Fleet. Retailer management (e.g. credit support). Administration of connections pioneer / rebate scheme. Supply, manage, test and maintain Energex field equipment (other than metering equipment). Responding to cold water reports. Network claim processing where distributor is at fault. External stakeholder interactions (regulatory, government and industry). Environmental health and safety management (risk assessment, monitoring, program management, reporting and training).		
AER service group—pre-connection services			
General connection enquiry services	Provision of standard information and general advice during connection enquiry. Includes provision of general connection information (e.g. supply availability) and services associated with assessing a connection applicant's enquiry and providing a response.	Standard control	Standard control

Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
Services associated with assessing a connection application, making a connection offer and negotiating offer acceptance. Includes: Application services to assess connection application and making of compliant connection offer. Undertaking design for small customer connection offer (excludes detailed design undertaken after a connection offer has been accepted) Carrying out planning studies and analysis relating to distribution (including sub-transmission and dual function assets) connection applications. Negotiation services involved in negotiating a connection agreement. Tender process – DNSP may carry out tender process on behalf of connection applicant or DNSP may assist connection application. Protection and Power Quality assessment prior to connection	Alternative control	Alternative Control
Additional support services provided by the DNSP (on request) during connection enquiry and connection application other than General Connection Enquiry Services and Connection Application Services. Generally relates to services which require a customised or site-specific response and/or are available contestably. Includes: ▪ site inspection in order to determine nature of connection (small or large customer connection) ▪ provision of site-specific connection information and advice for large customer connection. ▪ preparation of preliminary designs and planning reports for large customer connection ▪ customer build, own and operate consultation services.	Alternative control	Alternative control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
AER service group—connection services			
Small customer connections[282]	Design, construction, commissioning and energisation of connection assets for small customers. (Generally, small customers are those customers who connect under the Standard Asset Connection tariff class in the DNSP's pricing proposal[283].)	Standard control	Standard control
Large customer connections[284]	Design and construction of connection assets for large customers. (Generally, large customers are those customers who connect under the Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) tariff classes as per the distributor's pricing proposal[285].)	Alternative control	Alternative control
Commissioning and energisation of large customer connections	Connection and energisation of Large Customer Connection assets to allow conveyance of electricity. Inspection and testing of connection assets. Includes administration services involved in reconciling the financials of a connection project, processing and finalising network information and contracts in relation to a connection.	Alternative control	Standard control
Removal of network constraint for embedded generator	Augmenting the network to remove a constraint faced by an embedded generator.	Alternative control	Standard control
Temporary connections	Customer requests a temporary connection (e.g. temporary builders supply, blood bank vans, school fetes etc.).	Alternative control	Alternative control
AER service group—post connection services			
Operate and maintain connection assets	Works to operate, maintain, repair and replace connection assets owned by or gifted to the DNSP to a technically acceptable standard. Excludes works initiated by a customer, which is	Standard control	Standard control

282 Ergon Energy uses 'minor customer' in place of 'small customer'.
283 See the Energex and Ergon Energy tariff schedules, available at their websites: www.energex.com.au and www.ergon.com.au
284 Ergon Energy uses 'major customer' in place of 'large customer'.
285 See the Energex and Ergon Energy tariff schedules, available at their websites: www.energex.com.au and www.ergon.com.au

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	not required for the efficient management of the network or for DNSP purposes (such as customer requests to provide or maintain connection assets to a higher standard).		
Connection management services	Work initiated by a customer which is specific to a connection point. Includes: Supply abolishment. Move point of attachment. Re-arrange network assets – network assets are re-arranged at customer's request. Overhead service line replacement – customer requests the existing overhead service to be replaced .e.g. as a result of a point of attachment relocation. No material change to load. Auditing services – auditing of connection assets after energisation to network. Protection and power quality assessment. e.g. embedded generation connected to network. Customer requested works to allow customer or contractor to work close. ▪ coverage of low voltage mains (tiger tails) – customer requests the line close to a construction site to be physically covered in order to provide safety to parties work in close proximity ▪ Temporary disconnections and reconnection (including de-energisations and re-energisations) that may involve a line drop. e.g. community events. Supply enhancement. e.g. upgrade from single phase to three phase. Provision of connection services above minimum requirements. Upgrade from overhead to underground service. A reserve feeder is negotiated with customers specifically requesting continuity of supply should the feeder providing normal supply to their connection experiencing interruption.	Alternative control	Alternative control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	Customer consultation or appointment (if requested on B2B service order). Rectification of illegal connections or damage to overhead or underground service cables. Customer request for ad-hoc reconnections/disconnections for regular but short periods of time, for example holiday homes. De-energisation: ▪ Retailer requests de-energisation of the customer's premises (business or after hours) where the de-energisation can be performed (e.g. pole, pillar or meter isolation link). ▪ Retailer requests de-energisation of the customer's premises – Main switch seal (business or after hours). Re-energisation: ▪ Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account (business or after hours). ▪ Retailer requests a re-energisation of the customer's premises following a main switch seal (business or after hours). Reading provided for an active site. Retailer requests a re-energisation of the customer's premises after a physical disconnection and premises requires a visual examination.		
Accreditation of alternative service providers and approval of their designs, works and materials	Accreditation of service providers that meet competency criteria. Approval of third party design, works and materials: ▪ Review, Inspection and Auditing of design and works carried out by an alternative service provider prior to energisation. ▪ Certification of non-approved materials – approval of non-approved materials to be	Alternative control	Standard control / Alternative control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	used on the network.		
AER service group—metering services			
Type 5 and 6 metering installation	Includes on site connection of a new meter at a customer's premises, and on site connection of an upgraded meter at a customer's premises where the customer initiates the upgrade. Excludes installation of replacement types 5 and 6 meters initiated by the DNSP.	Alternative control	Standard control
Type 5 and 6 metering provision, maintenance, reading and data services	Meter provision refers to meter selection, procurement, programming, testing and management of NMI standing data according to the rules. Meter maintenance covers scheduled maintenance, meter inspection, load control relay maintenance, removal of meter and meter tampering. Meter reading refers to quarterly or other regular reading of a meter. Metering data services include collection, processing, storage and delivery of metering data, remote or self-reading at difficult to access sites, provision of metering data from previous 2 years, ongoing provision of metering data. Meter Data Services provided as part of general obligations as a local network service provider in accordance with the rules.	Alternative control	Standard control
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the Rules and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Standard control	Standard control
Auxiliary metering services	Off-cycle meter read, including: ▪ special meter reads ▪ move in move out meter reads	Alternative control	Alternative control / Standard control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	▪ check read – check the accuracy of the meter reading. Testing for type 5 and 6 meters - customer requested meter accuracy testing. Meter inspection and investigation – a request to conduct a site review of the state of the customer's metering installation without physically testing the metering equipment. Alterations and additions to current metering equipment, includes: ▪ meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment ▪ exchange meter – customer requests exchange of their current meter (e.g. for alternative metering configuration/consolidation of multiple meters for one meter), or customer requests exchange of their current meter for a solar photovoltaic meter. Provision of low voltage (LV) current transformers (CT). Type 5 to 7 non-standard metering data services. Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee. Meter re-seal – where the customer has caused the meter to need re-sealing (e.g. by having electrical work done on site). Install additional metering. Reconfigure meter. Meter Exit Fee – recovery of stranded assets costs associated with the removal of meter/s from customer's premises before the end of their useful life at the request of the customer (or customer's retailer) due to a change in Responsible Person /Meter Coordinator. Install load control.		

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	Remove local control relay or time clock.		
AER service group—ancillary network services			
Services provided in relation to a Retailer of Last Resort (ROLR) event	Distributors may be required to perform a number of services as a distributor when a ROLR event occurs. These include: Preparing lists of affected sites, and reconciling data with AEMO listings; handling in-flight transfers; identifying open service orders raised by the failed retailer and determining actions to be taken in relation to those service orders; arranging estimate reads for the date of the ROLR event and providing data for final network use of system (NUOS) bills in relation to affected customers; preparing final invoices for NUOS and miscellaneous charges for affected customers; preparing final debt statements; extracting customer data, providing it to the ROLR and handling subsequent enquiries; handling adjustments that arise from the use of estimate reads; assisting the retailer with the provision of network tariffs to be applied and the customer move in process; administration of any 'ROLR cost recovery scheme distributor payment determination'.	Alternative control	Not currently classified
Other recoverable works	Customer requests the provision of electricity network data including pole assess information. Specific request for the provision of zone substation data. Bundling of cables carried out at the request of another party. Provision of services, other than standard connection, for approved unmetered equipment, public telephones, traffic lights and public BBQs. Customer requested appointments. Attendance at customer’s premises to perform a statutory right where access is prevented. ▪ Rearrangement of assets (other than connection assets).	Alternative control	Alternative control

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
	Conversion to aerial bundled cables. ▪ Aerial markers. ▪ Parallel generator applications. ▪ Reserve feeder.		
AER service group—public lighting			
Provision, construction and maintenance of public lighting.	Application assessment, design, review and audit public lighting services. Provision, construction and maintenance of new street lighting services. Alteration, repair, relocation, rearrangement or removal of existing street light assets. Provision of glare shields, vandal guards, luminaire replacement with aero screens. A fee for the residual asset value of non-contributed public lights when removed from service before the end of their useful life at the request of the customer. Operating street lighting assets including handling enquiries and complaints and dispatching crews to repair assets.	Alternative control	Alternative control
Emerging or new public lighting technology.	New public lighting technologies, including trials. Energy efficient retrofit (including where customer requests to retrofit existing assets before end of life).	Alternative control	not classified

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
Unclassified distribution services			
Type 1 to 4 metering	Contestable metering services.	Unclassified	Unclassified
Emergency recoverable works	Work to repair damage to the distribution network caused by an identifiable third party from whom costs may be recovered.	Unclassified	Alternative control
Watchman	Unmetered light mounted on customer's property or distribution pole for security purposes. Charge for fixed capital cost of installing light.	Unclassified	Unclassified
Shared assets	Pole/duct rentals for non-electricity related purposes (e.g. telecommunications) and relocation of third party cables.	Unclassified	Unclassified
Non-distribution services that are unregulated			
Rental and Hire Services	Rental of Energex owned property.	Unregulated	Unregulated
Test, Inspect and Calibrate	Calibration and testing of equipment for external party products.	Unregulated	Unregulated
Property Searches	Undertaking conveyancing property searches.	Unregulated	Unregulated
Contracting Services to other NSPs	Services, such as specialist cable jointers, provided to other NSPs such as Ergon and Powerlink.	Unregulated	Unregulated
Provision of training to external parties	Specialist post and pre-trade training provided by EsiTrain to external parties.	Unregulated	Unregulated

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15
Equipment Services	Safety testing of equipment such as: ▪ insulating gloves ▪ live line hot sticks and rubber products ▪ insulating mats and covers ▪ voltage and phasing detectors, operational sticks ▪ harnesses, climbing kits, rescue kits ▪ step/extension ladders, pole platforms.	Unregulated	Unregulated
Sale of inventory, asset or scrap		Unregulated	Unregulated
Operate and Maintain large customer connections	Contract to provide operate and maintain services for connection assets owned by customer	Unregulated	Unregulated

Appendix C: Ergon Energy's request

Ref: JD/BC

Date: 31 July 2013

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Mr Warwick Anderson
General Manager – Network Regulation
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Email: QLDelectricity2015@aer.gov.au

Dear Mr Anderson

SUBMISSION ON WHETHER IT IS NECESSARY OR DESIRABLE TO AMEND OR REPLACE THE CURRENT FRAMEWORK AND APPROACH PAPERS

Thank you for the invitation to respond to your consultation on the current Framework and Approach (F&A) papers applying to Queensland Distribution Network Service Providers (DNSPs).

We understand that this consultation will assist the Australian Energy Regulator (AER) to make a decision on whether it is necessary or desirable to amend or replace matters in the current F&A for the next regulatory control period (i.e. 1 July 2015 to 30 June 2020).

We also understand that, in addition to decisions made under this consultation process, the AER must publish a F&A paper for:

- Any matters where no F&A currently applies; or
- Any matters where a DNSP requests an amendment or replacement in respect of that matter (pursuant to clause 6.8.1(c)(1) of the National Electricity Rules (Rules).

Ergon Energy believes that at least one of the matters addressed in the current 2010–15 F&A papers should be amended or replaced. Therefore, in accordance with clause 6.8.1(c)(1) of the Rules, Ergon Energy submits a written request to the AER outlining our reasons for its amendment or replacement. A copy of this request is provided at **Attachment 1**.

In addition to the matters the AER is required to consult on under clause 6.8.1(c)(2) of the Rules, we consider that all stakeholders would benefit from early consultation on:

- Other matters that form part of the current F&A which are not listed in clause 6.8.1(b) of the Rules – these are outlined in Chapter 5 of the AER's *Final F&A paper, Application of schemes, Energex and Ergon Energy 2010–15* (November 2008). We consider there would be benefit in clarifying which of these matters, if any, will apply in the F&A for the next regulatory control period.
- Additional matters not listed in clause 6.8.1(b) of the Rules but which may benefit from early consultation to ensure a smooth process for establishing revenue requirements and control mechanisms in the next regulatory control period. These are outlined below.

Ergon Energy Corporation Limited ABN 50 087 646 062
Ergon Energy Queensland Pty Ltd ABN 11 121 177 802

There are no other specific reasons warranting Ergon Energy to request an amendment for any other matter listed in clause 6.8.1(b). However, we anticipate that the AER will seek to consult on new matters not listed in the current F&A. We also expect that the AER may decide it is necessary and desirable to consult on other matters in the current F&A following decisions in other jurisdictions and the most recent changes to Chapter 6 of the Rules. We look forward to contributing to this consultation when it occurs.

Adjustments to revenue and pricing controls as a result of the expiry of certain transitional arrangements

Ergon Energy is aware that there are a number of transitional arrangements which will no longer apply in the next regulatory control period. The removal of these transitional arrangements will, in many circumstances, result in a change in how costs are recovered. There may be benefit in engaging early with stakeholders on how these arrangements will change and the impact on inputs to the Regulatory Proposal. In particular, there may be benefit in clarifying the arrangements to transition between regulatory control periods. Arrangements which will change include:

- The treatment of capital contributions in calculating the Annual Revenue Requirement;
- The treatment of solar feed-in tariffs;
- The treatment of assets included in the Regulated Asset Base that are used to provide standard control, alternative control and unregulated services under transitional arrangements;
- The recovery of charges for using the non-regulated 220kV network which supplies the Cloncurry township; and
- The recovery of entry and exit charges relating to non-regulated connection points between Powerlink's transmission network and our distribution network.

Revenue adjustments for the carry forward of over-recovery or under-recovery of revenue for this period

In order to establish an appropriate forecast of indicative prices in the Regulatory Proposal, there would be benefit in engaging on the approach the DNSP should take in the carry-forward of any over-recovery or under-recovery of revenues from the current regulatory control period.

Approach to Capital Contributions policy in the absence of NECF Rule requirements

Transitional arrangements apply to Ergon Energy in respect of our capital contributions policy. In the absence of National Energy Customer Framework rules applying to Ergon Energy in the next regulatory control period, we believe the may be benefit in engaging with stakeholders on how capital contributions arrangements will be applied in the next regulatory control period.

Should you require additional information or wish to discuss any aspect of our submission, please do not hesitate to contact Jenny Doyle, Group Manager Regulatory Affairs on (07) 4092 9813 .

Yours sincerely

Graeme Finlayson
Company Secretary and General Counsel
Ergon Energy

Attachment 1

Request to amend or replace the current Framework and Approach paper applying to Ergon Energy

Regulatory Provisions

Under clause 6.8.1(c)(1) of the National Electricity Rules (Rules), a Distribution Network Service Provider (DNSP) may request the Australian Energy Regulator (AER) in writing to make an amended or replacement Framework and Approach (F&A) paper in respect of certain matters that are set out in the F&A paper(s) currently applying to that DNSP. As identified in clause 6.8.1(b) of the Rules. Note, not all matters listed in this clause apply to Ergon Energy in the 2010–15 regulatory control period. As such, they are not discussed in the current F&A papers and the AER is required to make a F&A paper in relation to these matters under clause 6.8.1(a)(1) of the Rules. The request must specify the DNSP's reasons for making the request.

The request must be submitted by no later than 23 months before the end of the regulatory control period that precedes that for which the Distribution Determination is to be made. Clause 11.60.3(c) of the Rules. This transitional rule amends the 32 month timeframe outlined in clause 6.8.1(c)(1) of the Rules for Ergon Energy's 2015–20 regulatory control period. This means Ergon Energy must submit a request no later than 31 July 2013.

Matters set out in the current Framework and Approach paper

In Queensland, there are currently two F&A papers:

- Stage 1 – Classification of services and control mechanisms. This paper details the AER's likely approach to the classification of services and the control mechanisms to apply to Energex and Ergon Energy in the 2010–15 regulatory control period.
- Stage 2 – Application of schemes. This paper sets out the AER's likely approach to the application of the following incentive schemes in the 2010–15 regulatory control period:
  - Service Target Performance Incentive Scheme;
  - Efficiency Benefit Sharing Scheme; and
  - Demand Management Incentive Scheme.

  It also outlines the AER's consideration of other matters raised by Energex and Ergon Energy.

Matters to be amended or replaced

Ergon Energy requests that the classification of services set out in Appendix B of the *Final decision, Framework and approach paper, Classification of services and control mechanisms, Energex and Ergon Energy 2010–15* to be amended to include additional activities relating to the retrofitting of energy efficient street lights at a customer's request.

Ergon Energy further requests that the AER review (and, if appropriate, amend or replace) the elements of the two existing F&A papers that relate to matters not specified in clause 6.8.1(b).

Reasons

Under the current classification of services, Ergon Energy is unable to charge customers to replace an existing street light bulb with an energy efficient light bulb, even when the customer is willing to pay for this service. Therefore, we consider that it would be in the best interests of customers and Ergon Energy to introduce a new activity relating to this.

In relation to other elements of the existing F&A papers, Ergon Energy notes that these matters were included in the F&A papers published in accordance with the regulatory regime operating under the pervious of Chapter 6 of the Rules. Ergon Energy submits that a review of these additional elements is appropriate to determine whether they should remain in the F&A paper for the 2015-20 distribution determination.