



Final framework and approach

**Energex and Ergon Energy
Regulatory control period
commencing 1 July 2020**

July 2018

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Contents

Shortened forms.....	4
Overview	5
1 Classification of distribution services	14
1.1 .AER's proposed approach	15
1.2 .AER's assessment approach	16
1.3 .Reasons for AER's proposed approach.....	19
2 Forms of control	40
2.1 .AER's proposed approach	40
2.2 .AER's assessment approach	40
2.3 .AER's reasons — control mechanism and formulae for standard control services	44
2.4 .AER's reasons — control mechanism for alternative control services	54
3 Incentive schemes	59
3.1 .Service target performance incentive scheme	59
3.2 .Efficiency benefit sharing scheme	65
3.3 .Capital expenditure sharing scheme.....	69
3.4 .Demand management incentive scheme and demand management innovation allowance mechanism	73
4 Expenditure forecast assessment guideline	76
5 Depreciation	79
5.1 .AER's proposed approach	80
5.2 .AER's assessment approach	80
5.3 .Reasons for AER's proposed approach.....	80
Appendix A: List of submissions.....	83

Appendix B: Rule requirements for classification	84
Appendix C: Proposed service classification of Qld distribution services 2020–25	86

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
DMIA	demand management innovation allowance mechanism
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
DMIS	demand management incentive scheme
distributor, DNSP	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
next regulatory control period	1 July 2020 to 30 June 2025
opex	operating expenditure
RAB	regulatory asset base
STPIS	service target performance incentive scheme

Overview

The Framework and Approach (F&A) is the first step in a two-year process to determine efficient prices for electricity distribution services in Queensland (Qld). The F&A determines, amongst other things, which distribution services we will regulate and the broad nature of the regulatory arrangements. This includes an assessment of services (service classification) and whether we need to directly control the prices and/or revenues set for those services. The F&A also facilitates early consultation with consumers and other stakeholders and assists electricity distribution businesses to prepare regulatory proposals.

This final F&A has been prepared during the consultation period for our forthcoming Classification Guideline. We have incorporated some aspects of our approach to classification set out in the draft Guideline. However we anticipate, in light of submissions to the draft Guideline, that numerous revisions will be made. As a result, we anticipate that adjustments to the classification of services may be required at the time the regulatory proposal is submitted. We consider that the making of the Guideline may constitute a material change of circumstances.¹

Before reaching our proposed approach, we published a preliminary F&A for the Queensland distributors on 22 March 2018, seeking submissions from interested parties. Submissions closed on 27 April 2018, with 5 responses received, including a submission from our Consumer Challenger Panel. Appendix A lists the stakeholders who made submissions to this process.² We also held a meeting with interested stakeholders on 23 April 2018 to discuss our preliminary F&A.

Table 1 summarises our Qld distribution determination process.

¹ NER cl.6.12.3(b).

² All submissions are available on the AER's website at <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/aer-position>.

Table 1 Queensland distribution determination process

Step	Date
AER published preliminary F&A for Qld distributors	March 2018
Stakeholder forum	23 April 2018
Submissions on preliminary F&A for Qld distributors closed	27 April 2018
AER to publish final F&A for Qld distributors	July 2018
Qld distributors submit regulatory proposals to AER	January 2019
AER publishes issues paper and holds public forum	March/April 2019*
Submissions on regulatory proposal close	May 2019
AER to publish draft decisions	September 2019
AER to hold a predetermination conference	October 2019
Qld distributors to submit revised regulatory proposals to AER	December 2019
Submissions on revised regulatory proposals and draft decisions close	January 2020*
AER to publish distribution determinations for regulatory control period	April 2020

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

Source: NER, chapter 6.

Background

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution electricity and gas network businesses across Australia (excluding Western Australia). Our powers and functions for the electricity sector are set out in the National Electricity Law (NEL) and National Electricity Rules (NER).

Energex and Ergon Energy are the licensed, regulated operators of Queensland's (Qld) monopoly electricity distribution networks connected to the National Electricity Market (NEM). The distribution network comprises the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. The Qld distributors design, construct, operate and maintain their distribution network for Qld electricity consumers.

We make regulatory decisions on the revenues the Qld distributors can recover from their customers. We determine the Qld distributors' revenue by an assessment of their efficient costs and forecasts. Our assessment is based on a regulatory proposal submitted by the Qld

distributors in advance of a regulatory control period, in this case beginning 1 July 2020. Regulatory proposals set out the network businesses' views on their expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

The regulatory framework we administer is based on an incentive regime. We set a network business's allowed revenue for a period (typically five years) based on the best available information, rigorous assessment and consideration of consumers' views. Network businesses are then provided with incentives to outperform the revenue we determine. A network business retains any savings for a period of time before those savings are passed to customers through lower network bills.

This overview provides a summary of our proposed approach on:

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

It also sets out our decisions on:

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

We summarise below our approach to each of the above matters. More detailed discussion of each matter is set out in the following chapters.

Classification of distribution services

We regulate distribution services provided by the Qld distributors. Service classification determines which services will be regulated and how we will regulate services that are provided on a monopoly basis under a price or revenue cap, directly controlling the charges that a distributor can levy customers. Less prescriptive regulation is required where the prospect of competition exists. In some situations we may remove regulation altogether—unregulated distribution services must be provided through either a separate affiliate to the distributor or the distributor must demonstrate functional separation,³ following the introduction of our Ring-fencing Guideline.⁴

³ Functional separation may include physical separation of offices, staff separation, accounting separation and separate branding/avoiding cross-promotion. See AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, available at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017> and <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016>.

⁴ AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

In broad terms, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new distribution services that come into existence within a regulatory control period must be kept separate from direct control services, unless the distributor applies for, and receives, a waiver under the Ring-fencing Guideline.

Further, the Australian Energy Market Commission (AEMC) made a rule change to the NER in December 2017 which applies to the regulatory process for Qld electricity distributors for the 2020–25 regulatory period.⁵ As part of the AEMC's determination, we are required to develop and publish a Service Classification Guideline by September 2018, which will provide further clarity and transparency around how we classify services.⁶ In short, the rule change made it easier for us to change the classification of services regardless of how services have been historically classified. More specifically, the rule change removed the requirement for us to maintain a service classification unless another classification is clearly more appropriate.⁷ This mandatory requirement had previously constrained our ability to move away from the status quo when considering service classification.⁸

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

Table 2: Classifications of distribution services

Classification		Description	Regulatory treatment
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 a DNSP may earn 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 only by the local distributor.	We set service specific prices to provide a reasonable opportunity to enable the distributor to recover the efficient cost of each service from customers using that service.

⁵ See <http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services>.

⁶ Consultation on our Service Classification Guideline has commenced. See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines>.

⁷ Formerly NER, cl. 6.2.1(d), now deleted.

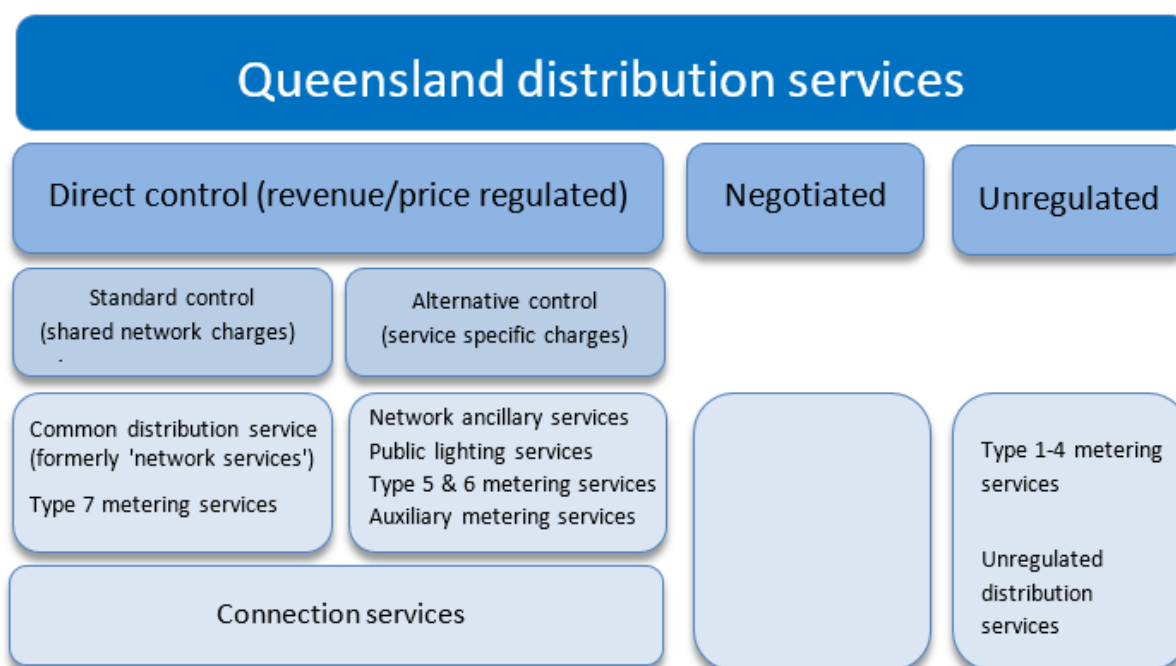
⁸ The rule change also requires us to develop and publish service classification guidelines by September 2018, which will provide further clarity and transparency around how we classify services. See clause 6.2.3A.

Negotiated service	Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services.	Distributors and customers are able to negotiate service and price according to a framework established by the NER. We are available to arbitrate if necessary.
Unregulated distribution services	Distribution services that are contestable will not be classified.	We have no role in regulating these services.
Non-distribution services	Services that are not distribution services. ⁹	We have no role in regulating these services.

Source: AER

Our proposed position is to change the classification of some Qld distribution services for the 2020–25 regulatory control period. While we propose to retain the existing service classifications for most services, we intend to clarify service descriptions to better align with the services provided. We also intend to create consistency and predictability across jurisdictions as far as practicable in how distribution services might be classified. Some additional metering services have been introduced as well as some slight adjustments to connection services, as identified in the preliminary F&A paper. An overview of our proposed service classifications for the Qld distributors is set out in figure 1 below.

Figure 1 AER proposed classification of Qld distribution services



Source: AER

⁹ The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system. NER, Chapter 10, glossary.

In relation to metering services, we note that the Qld Distribution Network Service Providers (DNSPs) were responsible for the provision of new and replacement type 5 and 6 meters up until 30 November 2017. Beyond that date, the Qld DNSPs continue to be responsible for existing meters until they are replaced (and entitled to levy associated charges). We refer to these as 'legacy meters' and will be classified as alternative control. All new meters (including replacements) installed from 1 December 2017 are considered to be 'contestable meters' and will not be provided by the Qld DNSPs. Going forward, customers can expect retailers to make arrangements for metering on their behalf.

There is an exception to the metering arrangements discussed above. Ergon Energy's Mount Isa-Cloncurry supply network is not part of the NEM and is therefore not covered by the new metering rules. Ergon Energy will continue to be solely responsible for these metering services, which will remain as alternative control services.

With respect to connection services, we have made a small number of adjustments to the classification of extension and augmentation services. One of the changes allows the DNSPs to treat some network extensions as additions to the shared network with funding from all customers rather than attributing the costs to a particular customer. There may be circumstances where this is reasonable because some extensions cannot be attributed to specific customers. The second change is to classify large customer augmentations as standard control which means the additional revenue, generated by a customer who has triggered an augmentation, will be taken into account when calculating whether a capital contribution from that customer is required. The DNSPs are required to set out how these changes will affect customers in their connection policies that must be submitted with the regulatory proposals.

Our final decision on service classification is not binding for our determination on the Qld network businesses' regulatory proposals. However, under the NER we may only change our classification approach in making our determination if we consider that a material change in circumstances justifies a departure from our final F&A position.¹⁰ Our Service Classification Guideline, which is due to be finalised in September 2018, could trigger some refinements to service classification as set out in this F&A paper. Any changes will be considered as part of the determination process.

Form of control

Following on from service classification, our determinations impose controls on direct control service prices and/or their revenues.¹¹ In deciding control mechanism forms, we must select one or more from those listed in the NER.¹² These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

¹⁰ NER, cl. 6.12.3(b).

¹¹ NER, cl. 6.2.5(a).

¹² NER, cl. 6.2.5(b).

Our decision on the form of control mechanisms for the Qld network businesses is to retain the long standing approaches of:

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

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

Our final decision on the form of control is binding on us and the Qld distributors for the 2020–25 regulatory determination.¹⁴ We may only vary our proposed control mechanism formulas in making the determination where we consider that a material change in circumstances justifies the departure.¹⁵

Incentive schemes

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

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

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

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline¹⁶ is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our proposed position is to apply the guideline, including its information requirements, to the Qld distributors in the 2020–25 regulatory control period.

Our 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

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

14 NER, cl. 6.8.1(b)(1)(i).

15 NER, cl. 6.12.3(c)(1).

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

apply the assessment/analytical tools set out in the guideline and any other appropriate tools for assessing expenditure forecasts.¹⁷

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

Depreciation

When we roll forward the Qld network businesses' regulatory asset bases (RABs) for the upcoming regulatory control period we must adjust for depreciation. Our proposed approach is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RABs as at 1 July 2025. In combination with our proposed application of the CESS, this approach will maintain incentives for the distributors to pursue capex efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

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

Dual function assets

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

Energex and Ergon Energy do not operate dual function assets. As such we are not required to make a decision on the application of either transmission or distribution pricing rules.

Consumer engagement

With the industry undergoing a period of rapid transformation, consumer engagement is becoming increasingly important in the development of proposals by network businesses. The increased focus on consumer engagement has led network businesses to commence engagement activities with consumers much earlier in the regulatory process than ever before.

Energex and Ergon Energy are following a set of engagement principles to ensure openness and transparency within the regulatory development process. The Qld distributors commenced their consumer engagement in December 2017 by hosting a '[Customer Xchange Forum](#)' which explored key energy issues with customers and customer advocacy groups. In early March 2018, they also held their first [Regulatory Proposal & Tariff Structure Statement Customer Council Working Group](#). Supporting their engagement activities is a draft community communication plan, published on their website (<https://www.talkingenergy.com.au/commitment>) for which they are also seeking public comment.

Energex and Ergon Energy were silent on consumer engagement in submissions. CCP sub-panel 14 recommended that the AER reinforce to Energex and Ergon Energy the importance

¹⁷ We are continuously improving the economic benchmarking techniques that are captured in our Guideline. This includes reviewing and refining our analysis of operating environment factors. See section 4 for more detail.

of a greater focus on the continuity and effectiveness of its consumer engagement in the lead up to submitting its proposal in January 2019. Consumer engagement has been disrupted by staff and role changes from their consolidation into Energy Queensland and subsequent restructuring, and CCP sub-panel 14 were of the view that their consumer engagement program is running behind that of other networks currently undertaking their reset process.¹⁸ Other networks going through their reset process began their consumer engagement 9-12 months earlier which gave them the opportunity for significant education of consumers on the reset process and how they can best contribute, which has facilitated deep and specific engagement on the reset related matters.¹⁹ CCP sub-panel 14 also encouraged the AER to provide more specific incentives around the effectiveness of a network's consumer engagement.²⁰

¹⁸ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 3.

¹⁹ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 14.

²⁰ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 4.

1 Classification of distribution services

This chapter sets out our proposed approach on the classification of distribution services provided by the Qld distributors in the 2020–25 regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services²¹
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

Our classification decisions therefore determine which services we will regulate and how distributors will recover the cost of providing those regulated services. We introduced our Ring-fencing Guideline for electricity distributors and our classification decisions will also settle ring-fencing obligations that will apply to each Qld distributor for the 2020–25 regulatory control period.²² For these reasons, we have closely reviewed the table of distribution services at appendix C.

The Australian Energy Market Commission (AEMC) recently made changes to the NER, following two rule change proposals from the Council of Australian Governments Energy Council and the Australian Energy Council, on contestability of energy services.²³ The new rule streamlines the classification provisions and requires us to develop and publish a Service Classification Guideline by 30 September 2018. More specifically, the NER has removed the requirement for us to maintain the current service classification unless another classification is clearly more appropriate. Removing this provision provides an opportunity to improve clarity, and achieve greater consistency across jurisdictions as far as practicable. It also provides more predictability in how distribution services might be classified and service descriptions that better align with the services being provided.

The Service Classification Guideline will set out our approach to service classification under the Rules. As a guide for distributors, it will also contain a baseline list of distribution services along with our view on how these services would be classified. The Service Classification Guideline will not bind us or the DNSPs. However, we are required to set out our reasons for any departure from the guideline to provide transparency to stakeholders in circumstances where our approach differs from that in the classification guideline. We anticipate DNSPs will need to depart from the approach set out in the Guideline. Departures can be expected

²¹ Control mechanisms available for each service depend on their classification. Control mechanisms available for direct control services are listed by clause 6.2.5(b) of the NER. These include caps on revenue, average revenue, prices and weighted average prices. A fixed price schedule or a combination of the listed forms of control are also available.

Negotiated services are regulated under part D of chapter 6 of the NER.

²² AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

²³ See <http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services>.

because of different licensing obligations on DNSPs and service contestability between the different jurisdictions.

Consultation on the development of the Service Classification Guideline is ongoing. We published our draft guideline for comment in June 2018.²⁴ Work on the new Service Classification Guideline has been occurring in parallel to this final F&A. As such, we anticipate that adjustments to the classification of services for Qld distributors may be required at the time the regulatory proposal is submitted. It is likely that we will consider that changes to the Guideline between its draft and final versions constitute a material change of circumstances.²⁵ This could justify further refinement to the classification of services set out in this F&A paper.

1.1 AER's proposed approach

Overall, our proposed approach is to change the classification of some Qld distribution services for the 2020–25 regulatory control period.

Our proposed approach is to group distribution services provided by the Qld distributors as:

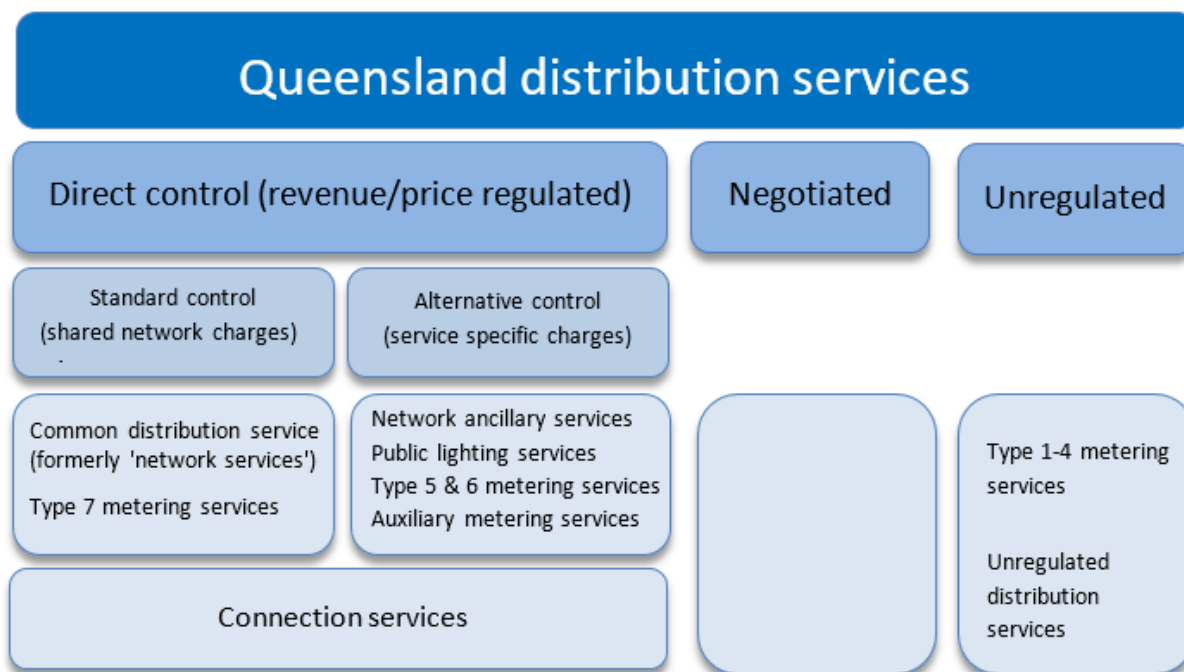
- common distribution services (formerly 'network services')
- connection services
- metering services
- network ancillary services
- public lighting services
- unregulated distribution services.

Figure 1.1 summarises our proposed classification of Qld distribution services. Our assessment approach and reasons follow.

²⁴ As part of the consultation process so far for the development of the guideline, we produced an issues paper inviting submissions by interested parties. In response, we received eight submissions from industry stakeholders on a broad range of issues, which can be found at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines>.

²⁵ NER cl.6.12.3(b).

Figure 1.1 AER proposed approach to classification of Qld distribution services



Source: AER

1.2 AER's assessment approach

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

- classify the service, rather than the asset²⁶ – we can only decide on service classification if we understand the service being provided. That is, distribution service classification involves the classification of services distributors directly supply to customers. It does not involve the classification of:
 - the assets used to provide such services
 - the inputs/delivery methods distributors use to provide such services to customers, or
 - services that consumers or other parties provide to distributors.
- classify distribution services in groups²⁷ – our general approach to service classification, where it is practical to do so, is to classify services in groupings rather than individually. This obviates the need to classify services one-by-one and instead defines a service

²⁶ The AEMC's Contestability of energy services rule change, made in December 2017, introduced a requirement for the AER to regulate 'restricted assets'. The AER does not classify assets as restricted assets; rather, the term is defined in the NER. The AER only has a role in assessing applications for exemptions from the restricted assets provisions of the NER.

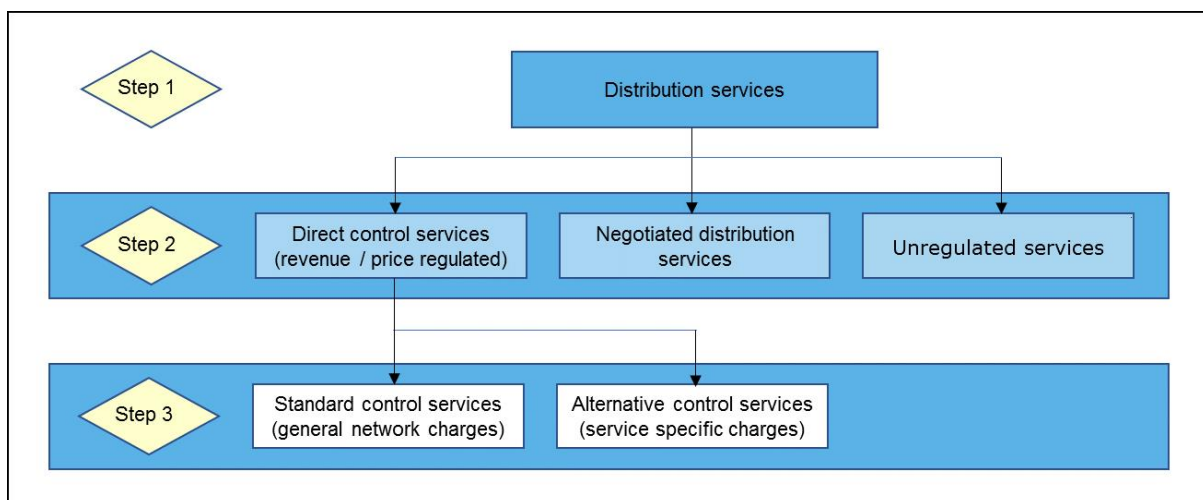
²⁷ NER, cl. 6.2.1(b).

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

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

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

Figure 1.2 Distribution service classification process



Source: NER, chapter 6, part B.

As illustrated by figure 1.2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system.²⁸ A distribution system is a 'distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.²⁹
- We then consider whether economic regulation of the service is necessary (step 2). When we do not consider economic regulation is warranted, we will not classify the service.³⁰ If economic regulation is necessary, we consider whether to classify the service as either a direct control or negotiated distribution service.
- When we consider that a service should be classified as direct control, we further classify it as either a standard control or alternative control service (step 3).

When deciding whether economic regulation of the service is necessary (step 2), the NER requires us to have regard to the 'form of regulation factors' set out in the NEL.³¹ We have reproduced these at appendix B. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The NER also requires us to consider the desirability of consistency in the form of regulation for similar services both within and beyond the jurisdiction.³²

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.³³ These include the potential to develop competition in the provision of a service and how our classification may influence that potential, whether the costs of providing the service are directly attributable to the person to whom the service is provided, and the possible effect of the classification on administrative costs.

Our classification decisions determine how distributors will recover the cost of providing services.³⁴ Distributors recover standard control service costs by averaging them across all customers using the shared network. This shared network charge forms the core distribution component of an electricity bill. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. We set service specific prices to enable the distributor to recover the full efficient cost of each service from the customers using that service. At a high level, a service will be classified as an alternative control service if it is either:

- potentially contestable, or

²⁸ NER, chapter 10, glossary.

²⁹ NER, chapter 10, glossary.

³⁰ NER, cl 6.2.1(a) note.

³¹ NER, cl. 6.2.1(c)(1); NEL, s. 2F.

³² NER, cl. 6.2.1(c).

³³ NER, cl. 6.2.2(c).

³⁴ We regulate distributors by determining either the prices they may charge (price cap) or by determining the revenues they may recover from customers (revenue cap).

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

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

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

In the case of some distribution services, we may determine that there is sufficient competition for these services and there is no need for us to classify the service as either a direct control service or a negotiated distribution service. That is, the market is competitive, allowing customers to shop around for the best price. We refer to these distribution services as 'unregulated distribution services'. Pursuant to our Ring-fencing Guideline, all unregulated distribution services or new distribution services that come into existence within a regulatory control period must be kept separate from direct control services, unless the distributor applies for and receives a waiver under the Ring-fencing Guideline.³⁵

1.3 Reasons for AER's proposed approach

This section sets out our proposed service classification and reasons for the Qld distributors' 2020–25 regulatory control period for each service group.

Appendix C contains a detailed table of our proposed classification of Qld distribution services.

CCP sub-panel 14, Ergon Energy and Energex generally supported our proposed classification.³⁶

Common distribution service

³⁵ AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

³⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 4; Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 2.

This service group was formerly called 'network services'. However, to avoid confusion with the defined terms in chapter 10 of the NER, we propose to rename this service group 'common distribution service'. This term was supported by CCP sub-panel 14.³⁷

The common distribution service is a suite of activities concerned with providing a safe and reliable electricity supply to customers.³⁸ Activities within the common distribution service group are intrinsically tied to the network infrastructure and the systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution service activities on a regular basis. Providing a common distribution service involves a variety of different activities, such as the construction and maintenance of poles and wires used to transport energy across the shared network. The precise nature of activities provided to plan, design, construct and maintain the shared network may change over time. Regardless of what activities make up the common distribution service, this service group reflects the provision of access to the shared network to customers.

During consultation with the AER, the Qld distributors proposed a revised description that we consider is clearer and more comprehensive than our preliminary description.³⁹ We have adopted the revised description, contained in appendix C, which brings the description of a common distribution service in Qld in line with NSW, ACT, Tasmania and the NT.

Our proposed approach is to classify the common distribution service group as a direct control service. Energex and Ergon Energy both hold an electricity distribution authority to provide these services, which is the only distribution authority in place for their respective geographic areas.⁴⁰ Under the *Electricity Act 1994* (Qld), a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so.⁴¹ These arrangements create a regulatory barrier, preventing third parties from providing activities within the common distribution service group.⁴² Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of activities classified as a common distribution service.

We must further classify direct control services as either standard or alternative control services.⁴³ Our proposed approach is to retain the current standard control classification for the common distribution service. There is no potential to develop competition in the market for common distribution service activities because of the barriers outlined above.⁴⁴ There would be no material effect on administrative costs for us, the Qld distributors, users or

³⁷ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 2.

³⁸ NER, Chapter 10 glossary.

³⁹ Energex and Ergon Energy letter, *Request to amend the framework and approach*, 31 October 2017, p.1.

⁴⁰ Authorities are issued by the Director General of Qld's Department of Energy and Water Supply.

⁴¹ 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.

⁴² NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).

⁴³ NER, cl. 6.2.2(a).

⁴⁴ NER, cl. 6.2.2(c)(1).

potential users by continuing this classification.⁴⁵ We currently classify the common distribution service (previously 'network services') in Qld and all other NEM jurisdictions as standard control services.⁴⁶ Further, distributors provide activities listed within the common distribution service through a shared network and therefore cannot directly attribute the costs of these services to individual customers.⁴⁷

Support for another distributor during emergency event

In consultations with staff, the Qld distributors have requested a new activity to be listed under the common distribution service heading, labelled "support for another distributor during an emergency event".

When a distributor provides assistance to another distributor during an emergency event, for instance to help repair the network, this activity is provided in connection with a distribution system. Therefore, we consider it an activity provided under the common distribution service.⁴⁸ The activity, therefore, forms part of the common distribution service.

In the case of either Energex or Ergon Energex supporting another distributor, including each other – in an emergency event – the works performed are not on their own shared networks and so they are entitled to recover the costs of the assistance provided. While we propose to classify these activities as standard control, in line with the classification of the common distribution service, the distributor is still expected to seek recovery of the costs of the assistance provided. Going forward, we propose to adopt this approach across all NEM jurisdictions.

Energex and Ergon Energy did not make any specific comments regarding this approach in their submission. CCP sub-panel 14 supported the allocation of this service as a common distribution service, provided that we have confidence that the recovery of fair and reasonable costs by the service provider will occur.⁴⁹

Load control devices

The Qld distributors have a long established history of using demand management to influence the profile of demand for electricity across the day. Demand management can assist distributors to reduce or avoid costly network investment in response to growth in peak electricity demand.

Demand management undertaken by DNSPs can take many forms. For example, a distributor might directly undertake demand management activities or acquire demand management from third parties (such as load aggregators). Activities undertaken could

⁴⁵ NER, cl. 6.2.2(c)(2), (3).

⁴⁶ NER, cl. 6.2.2(c)(4).

⁴⁷ NER, cl. 6.2.2(c)(5).

⁴⁸ NER, chapter 10, glossary.

⁴⁹ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 5.

involve incentive payments to encourage certain behaviours by customers (such as payment for controlling peak smart devices or controlled load tariffs) or involve investment in equipment such as load control devices. It should be noted that the associated expenditures may be recorded as operating or capital expenses. Irrespective, demand management activities are undertaken to reduce the cost of providing services to all consumers, albeit that a particular incentive may be directed to a specific customer. For this reason, we are satisfied that acquisition of demand management is an activity that is provided as an input to the 'common distribution service'.

In the past, distributors have tended to undertake demand management. Moving forward, we expect that third parties will play a greater role in offering demand management to distributors. Ultimately, however, distributors will continue to play a key role in funding demand management activities on behalf of consumers, whether the services are provided by distributors or by third parties. For this reason, we have explicitly identified the acquisition of demand management as an input to the 'common distribution service' in the list of distribution services.

AGL Energy Limited (AGL) submitted that the preliminary F&A failed to clarify the provision of current standard control services that are aimed at the control of customers' load control.⁵⁰ Network businesses offer a controlled load tariff to customers prepared to have appliance loads, such as hot water, directly controlled by the DNSP. AGL argued that this is not a uniform service provided to the majority of electricity customers as the customers pay a different, lower tariff for the controlled load and is provided with a unique product that is offered to and selected by the customer. Thus, AGL queried why it is included as a standard control service and were of the view that classifying this service as a standard control service effectively precludes competition for the delivery of load management services, despite the fact that networks have previously argued for its inclusion as a standard service.⁵¹

The different means by which demand management can be effected means there is a degree of competition between these different sources. While controlled loads tariffs will remain the purview of DNSPs, other forms of managing demand, such as through direct load control can be provided by alternative service providers. We note the new rules relating to restricted assets⁵² may also be relevant to the future use of load control devices by DNSPs.

AGL also questioned the inclusion of 'network demand management for distribution purposes' within the common distribution services. AGL submitted that it is uncertain whether this refers to legacy load control services, the potential demand management input activities under incentive schemes or the provision of other demand management services to customers.⁵³ To be clear, demand management in this context refers to the requirement for DNSPs to seek demand management services from the market as an input to the common

⁵⁰ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 2.

⁵¹ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 2.

⁵² NER, cl. 6.4B.

⁵³ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

distribution service. It is a service DNSPs obtain from the market, whether by direct investment in load control devices (where permitted) or the procurement of such services from third party providers. It is not a service a DNSP offers to customers.

Emergency recoverable works

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

Given that these services are provided in connection with a distribution system, we consider this a distribution service. In the current regulatory control period, we did not classify this service in Queensland. Therefore, the service was unregulated.⁵⁴ This was because the cost of these works could be recovered through other avenues (e.g. under common law). However, following the introduction of our Ring-fencing Guideline, we have had cause to consider the classification of this service. As an unregulated distribution service, it would be subject to ring-fencing, which could increase the cost of these activities. Instead, we intend to classify this service as direct control. Therefore, our proposed approach is for emergency recoverable works to be subsumed into the common distribution service group and classified as a direct control and standard control service. Distributors are required to perform works to maintain or repair the shared network to ensure a safe and reliable electricity supply. Ergon Energy, Energex and CCP sub-panel 14 supported this classification.⁵⁵

Although we propose to classify this service as a standard control service, a distributor is still expected to seek recovery of the cost of these emergency repairs from the third party where possible. CCP sub-panel 14 noted that there are risks regarding whether or not network distributors will continue to be incentivised to recover the costs if the expense will be 'budgeted' for in overall operating costs.⁵⁶ Further, CCP sub-panel 14 expressed concern if distributors could recover the cost of the repairs twice (from consumers and the third party).⁵⁷ We note these concerns. Where a distributor is successful in recovering the cost of the emergency repairs from a third party, this payment or revenue would be netted off from expenditure on regulated activities and hence forecasts in the future. This would prevent a distributor from recovering the cost of emergency repairs twice—as a standard control charge across the broader customer base and from the responsible third party. Going forward, we propose to adopt this approach across all NEM jurisdictions.

Connection services

⁵⁴ AER, Final framework and approach for QLD electricity distribution businesses, April 2014, p. 37.

⁵⁵ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 2; Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, pp. 4–5.

⁵⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs Networks*, 4 May 2018, p. 5.

⁵⁷ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs Networks*, 4 May 2018, p. 5.

Queensland distributors arrange their connection services into three components: premises connections, extensions and augmentation. Customers use these components depending on their size and the nature of their connection. The distributors also provide other connection services to facilitate the physical connection to the distribution network. These services are comprised of connection management services and enhanced connection services.

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

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

In Queensland, small customers⁵⁸ who require a basic connection – without the need for an extension or augmentation – typically do not pay for connection to the network. This is because the tariffs to be paid by small customers typically exceed the cost of connection. Hence, all customers benefit from the connection of these customers. We treat major customers⁵⁹ slightly differently because these connections are contestable. In order to facilitate competition, a DNSP charges a large customer the full cost of premises connection.

If a customer connection requires an extension or augmentation of the network, additional payments may be required. A capital contribution may be required where the cost of connection exceeds forecast tariff payments (revenues). These charges are explained in a DNSP's connection policy, which must be consistent with our Connection Charge Guideline⁶⁰. The DNSPs are required to submit connection policies with their regulatory proposals.⁶¹ A high-level overview regarding each of the components and our approach to their classification are outlined below.

Premises connections

Premises connections includes the design, construction, commission and energisation of connection assets. In Qld, customers who require premises connection are divided into two classes, dependent upon the capacity of connection required.

Small customer connections are typically those who require a basic, low-voltage connection that will not involve any extension or augmentation of connection assets at the connection point.⁶² Our proposed approach is to maintain the current classification⁶³ for small customer

⁵⁸ In their connection policies, the Qld distributors define a small customer as one who falls within the Standard Asset Customer (SAC) tariff class.

⁵⁹ Qld distributors define major customers as those who fall within the Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) tariff classes.

⁶⁰ See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/national-electricity-connection-charge-guideline-2012>.

⁶¹ NER cl. 6.8.2(5A).

⁶² E.g. Energex connection policy 2015: https://www.energex.com.au/_data/assets/pdf_file/0003/340752/Energex-

premises connections as direct control and further, as a standard control service for the 2020–25 regulatory period. This is consistent with the current regulatory approach.⁶⁴

Major customer connections either require higher voltage, with a network coupling point at or above 11kV,⁶⁵ or have higher forecast demand, which falls into a major customer category.⁶⁶ We propose to retain the current classification of most major customer connections as direct control and alternative control services in line with their current classification.⁶⁷ This classification means that major customers are required to fund in full all new connection assets required for connection to the distribution network. Major customer connections are subject to some competition in Queensland.

Extensions

Extensions of the network to facilitate a connection fall into three broad categories, dependent upon the customer's circumstances:

- A new or altered connection major customer connection "where the network extension will be dedicated to the exclusive use of the major customer at the time of installation and energisation and there is *no reasonable likelihood* that the network extension will be used to supply another customer or customers within the time period set out in the distributor's Connection Policy."⁶⁸ We propose to continue to classify these services as direct control and further, as alternative control in line with their current classification.
- A new or altered connection major customer connection "where the distributor considers there *is a reasonable likelihood* that the network extension will be used to supply another customer or customers within the time period set out in the distributor's Connection Policy (i.e. will form part of the shared network)."⁶⁹ We propose to classify these services as direct control and further as standard control. This represents a change from the current regulatory control period, where we classified the service as alternative control.
- We consider a classification of standard control is appropriate when a service is not provided competitively or where it is not possible to identify the beneficiary of a particular connection asset.⁷⁰ That is, the connection asset is shared. Connections that are classified as standard control services also allow for the additional revenue that the DNSP subsequently receives (that is, from providing other services by means of the

[Connection-Policy-201520.pdf](#), p. 8.

⁶³ AER Final decision Qld electricity distribution determination, Attachment 13, Classification of services - October 2015, p. 7.

⁶⁴ NER cl. 6.2.2(c)(3).

⁶⁵ See Energex's connection policy for the current regulatory period available on the Energex website: Energex connection policy 2015: https://www.energex.com.au/__data/assets/pdf_file/0003/340752/Energex-Connection-Policy-201520.pdf

⁶⁶ See Ergon Energy's connection policy: https://www.ergon.com.au/__data/assets/pdf_file/0017/228401/Ergon-Energy-Connection-Policy.pdf

⁶⁷ AER, *Final framework and approach for Ergon Energy and Energex*, April 2014, p.44 and NER 6.2.2(c)(3).

⁶⁸ See appendix C: Connections; Extensions. Emphasis added.

⁶⁹ See appendix C: Connections; Extensions. Emphasis added.

⁷⁰ NER cl. 6.2.2(c)(1)&(5).

connection) to be considered as an offset to customer connection costs, which encourages efficient customer connections and this is in the interests of all consumers.⁷¹

- A new or altered small customer connection – as determined by the distributor's connection policy. We propose to classify extensions to small customers as a direct control service and further as standard control, in line with the classification in the current regulatory control period.⁷²

Augmentation

Augmentation is any enlargement or enhancement to the shared network, undertaken by a distributor, which is not an extension. In most cases, the appropriate classification for augmentation is as direct control and further as a standard control service. This is because, in most cases, the benefits of augmentation are not fully captured by the person for whom the service is provided but are shared across the network. As a standard control service, augmentation is subject to a cost revenue test applied to the person to whom the service is provided, who may be required to pay a capital contribution to the costs of the augmentation. Augmentation falls into three broad categories:

- A new or altered major customer connection. We propose to classify augmentation services for major customers as direct control and further as standard control services. This is a departure from the current regulatory control period. As with extensions, a standard control classification does not imply that these costs are spread across all consumers. Rather, these augmentation costs will be considered in the context of the full costs of a customer connection and compared with the additional revenue the customer will pay to the DNSP over time.⁷³
- A new or altered small customer connection. We propose to classify augmentation services for small customers as direct control and further as standard control services. This represents a continuance of past practice.⁷⁴
- The removal of a network constraint faced by an embedded generator. As the costs for this service can usually be fully attributed to the person for whom the service is provided, we propose to classify this service as direct control and further as an alternative control service. This is in line with the current classification.⁷⁵ Consistent with its current connection policy, Energex advised that despite the classification, it may fund the shared network augmentation if there is a demonstrable net benefit to other network users.⁷⁶

Connection management services

⁷¹ NER cl. 5A.E.1(c)1.

⁷² NER cl. 6.2.2(c)(3).

⁷³ NER cl. 5A.E.1(c)2.

⁷⁴ NER cl. 6.2.2(c)(3).

⁷⁵ NER cl. 6.2.2(c)(3) & (5).

⁷⁶ Energex's current Connection Policy July 2015, p. 28:

https://www.energex.com.au/__data/assets/pdf_file/0003/340752/Energex-Connection-Policy-201520.pdf.

Connection management services is the grouping which covers a range of services and activities provided by distributors, and sought by customers, which are specific to a connection point. This service grouping subsumes services that were previously classified as "connection application services" and "disconnection/reconnections". Energex and Ergon Energy provide these services under their distribution authorities. Given this barrier to competition, our proposed approach is to classify this service group as direct control services.⁷⁷ The benefits and cost of the services can be attributed to the person for whom the service is provided. As such, we further propose to classify connection management services as alternative control services.⁷⁸

Our proposed approach is consistent with the current classification for such services.⁷⁹ As a result, there would be no material effect on administrative costs of regulation, Queensland electricity distributors, users or potential users.

We did not receive any submissions on our preliminary position on this issue.

Enhanced connection services

Enhanced connection services are activities to provide customers with a higher standard of electricity supply that exceeds the minimum technically feasible standard. These include services where customers request higher levels of reliability or three-phase electricity. Where the Queensland distributors offer these services, we propose to classify them as direct control, and further as alternative control services. This approach is justified on the following basis:

- The services are provided to individual customers upon request, rather than to all customers.
- The classification is administratively efficient, and consistent with previous regulatory approaches for many DNSPs' services.
- The classification promotes a consistent regulatory approach to similar services within and across jurisdictions.

Enhanced connection services is a new connection service grouping for the Queensland distributors. This new grouping provides additional clarity for stakeholders and may help facilitate competition in the future. The Queensland distributors should clarify how the service is provided and explain how charges for the service will be levied in their connection policy for the forthcoming regulatory period.

A key consideration for us in deciding whether to classify a distribution service is the extent and effectiveness of competition in the market for the service.⁸⁰ We also take into account the existence and extent of any barriers to entry by alternative service providers. In

⁷⁷ NEL, s. 2F(a).

⁷⁸ NER cl. 6.2.2(c)(5).

⁷⁹ AER, *Final framework and approach for Ergon Energy and Energex*, April 2014, p. 52.

⁸⁰ NEL, s. 2F.

preliminary discussions with the distributors, Energex indicated that around 70 per cent of the design and construction of contestable major customer connection assets are being provided by alternative providers. In Ergon Energy's distribution area, around half of new major customer connections are provided through competitors. As a result, we consider that the Queensland distributors are still able to exercise monopoly power in this market, although we will review this position in future regulatory periods.

The Electrical Trades Union (ETU) supported our position to classify connection services as direct control services.⁸¹ The ETU also wanted to place on record its strong opposition to any decision to re-classify any connection service to an unregulated service.

CCP sub-panel 14 submitted that the cost of connections for major customers should, as much as possible, be user pays and should not be an opportunity for a network to make a capital contribution that increases the regulatory asset base (RAB) for all consumers.⁸²

The Queensland Council of Social Service (QCOSS) disagreed with our decision to change the classification for extensions for large customers and strongly advocated that all major customer augmentations and extensions continue to be classified as alternative control services. QCOSS were of the view that although there is some degree of monopoly service, there is a large contestable market (particularly in the Energex area) and classifying these services as standard control is likely to reduce competition in the provision of these services. They argued further that major customers will be able to connect without paying specific charges for these services, which will not be provided by Energex and/or Ergon Energy.

Further, QCOSS argued that where a second customer benefits from an extension or augmentation within a reasonable period of time, distributors already have mechanisms in place to manage the situation. QCOSS were concerned that our position to allocate extensions to the common distribution service where the distributor considers there is a reasonable likelihood that the network extension will be used to supply another customer within the time period set out in the distributor's Connection Policy, is very vague and non-transparent. QCOSS submitted that major customer connections and augmentations should remain classified as alternative control services as the major customer is the beneficiary, the major customer is identifiable and no other parties benefit from the investment.⁸³

We agree with QCOSS insofar as major customers should be required to carry the full cost of their connections, particularly where it is clear that they are the primary beneficiary to the service being requested. However, it should be noted that augmentation of the networks benefits all users of that network. As each new customer that joins the network pays their incremental costs and also contributes to shared costs, all users benefit. Where QCOSS and CCP sub-panel 14 have expressed concern regarding the equitable sharing of the costs of network extensions and augmentations, we note that under a standard control service

⁸¹ Electrical Trades Union, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 1.

⁸² Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 7.

⁸³ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, pp. 2–3.

classification, costs are subject to a cost revenue test. This test takes into account the incremental revenue the connection will generate against the incremental cost, with the customer bearing the cost of any shortfall via a capital contribution. The Connection Policy published by the distributors outlines how these contributions are calculated.

Metering services

All electricity customers have a meter that measures the amount of electricity they use.⁸⁴ On 26 November 2015, the AEMC made a final rule to open up competition in metering services and give consumers more opportunities to access a wider range of metering services.⁸⁵

The competitive framework is designed to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay. Improved access to the services enabled by advanced meters will provide consumers with opportunities to better understand and take control of their electricity consumption and the costs associated with their usage decisions.⁸⁶

The final rule alters who has overall responsibility for the provision of metering services by providing for the role and responsibilities of the Responsible Person to be performed by a new type of Registered Participant – a Metering Coordinator. Any person can become a Metering Coordinator subject to satisfying certain registration requirements.⁸⁷

Retailers are required to appoint the Metering Coordinator for their retail customers. The final rule also includes a number of other features to support the competitive framework for the provision of metering services, including consumer protections⁸⁸ and an ability for consumers to opt out of having an advanced meter installed if they have an existing, working meter.⁸⁹

The new arrangements commenced on 1 December 2017 and required changes to the NER and the National Electricity Retail Rules (NERR).⁹⁰ Consequently, our proposed classification of some metering services will also change for the 2020–25 regulatory control period.

Type 1 to 4 metering services

Type 1 to 4 meters provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. Type 1 to 4 meters are competitively available and we do not currently regulate them in Qld or in most other

⁸⁴ All connections to the network must have a metering installation (NER, cl. 7.8.1(a)).

⁸⁵ AEMC, *Competition in metering services information sheet*, 26 November 2015.

⁸⁶ AEMC, *Competition in metering services information sheet*, 26 November 2015.

⁸⁷ AEMC, *Competition in metering services information sheet*, 26 November 2015.

⁸⁸ AEMC, *Competition in metering services information sheet*, 26 November 2015.

⁸⁹ AEMC, *Final rule to increase consumers' access to new services information sheet*, 26 November 2015.

⁹⁰ AEMC, *Competition in metering services information sheet*, 26 November 2015.

jurisdictions⁹¹—they are not classified and therefore are unregulated distribution services and our proposed approach is for them to remain so.

QCOSS referred to 5500 type 4 smart meters funded by the Queensland Government, as part of the Energy Savvy Families program,⁹² prior to the Power of Choice Reforms. They submitted that it is not clear if the amendments to the National Energy Retail Rules with respect to metering contestability apply to these meters. QCOSS suggested that Ergon Energy should not be allowed to recover capital costs associated with the next phase of the program, which includes the rollout of a further 4000 smart meters.⁹³ We note QCOSS' concerns. Under the metering contestability framework, DNSPs cannot provide type 4 meters. Existing type 1 to 4 meters were to be transferred to retailers by 1 December 2017. Energy Queensland have confirmed that all outstanding smart meters installed under the Energy Savvy Families Program were transferred to the metering coordinator: Metering Dynamics. We are working with all DNSPs, including Energex and Ergon Energy, to ensure that any remaining meters are transferred to contestable metering providers in a timely manner.

Type 5 and 6 metering services

Up until 1 December 2017, the Qld distributors were the monopoly providers of type 5 (interval) and 6 (accumulation) meters. However, from 1 December 2017 (and therefore before the commencement of the next regulatory control period on 1 July 2020), metering services across the NEM became contestable. Therefore, since 1 December 2017, the Qld distributors are no longer permitted to install or replace type 5 or 6 meters (although the Qld distributors will continue to provide a number of other type 5 and 6 metering services to support the continued operation of existing type 5 and 6 meters). For this reason, new type 5 and 6 meter provision and new installation services are no longer permitted under the NER from 1 December 2017.

Therefore, our proposed approach is to not classify these services for the 2020–25 regulatory control period. However, the Qld distributors may still recover the capital cost of type 5 and 6 metering equipment installed prior to 1 December 2017 as an alternative control service. Type 5 and 6 metering services were unbundled from standard control services in our final determination for the 2015–20 regulatory control period⁹⁴ to promote customer choice and remove any classification barriers limiting contestable provision of these meters. This approach aligned with AEMC's Power of Choice recommendations to unbundle metering costs from shared network charges.⁹⁵

⁹¹ AEMC. *Expanding competition in metering and related services, Rule Determination*, November 2015, p.6.

⁹² See: <https://www.qld.gov.au/housing/buying-owning-home/energy-water-home/electricity/digital-meters/energy-savvy-families>.

⁹³ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, p. 3.

⁹⁴ AER, *Final decision Energex / Ergon Energy 2015–20 regulatory control period, Attachment 13 Classification of services*, April 2015, pp. 13–10.

⁹⁵ AEMC, *Consultation paper — National electricity amendment (expanding competition in metering and related services)*, April 2014.

Ergon Energy and Energex noted that as the Mount Isa-Cloncurry network in Ergon Energy's distribution area is exempt from chapter 7 of the NER and therefore not subject to Power of Choice, Ergon Energy will continue to install type 6 meters in this area.⁹⁶

Type 7 metering services

Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. Charges associated with type 7 metering services relate to the process of estimating electricity use. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation and the light bulb wattage. Qld distributors are the monopoly providers of type 7 metering services in Qld.⁹⁷

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.⁹⁸ We intend to classify type 7 metering services as direct control services and further, as standard control services. This is a continuation of the current classification of type 7 metering services.⁹⁹ We did not receive any submissions on our preliminary position on this issue.

Auxiliary metering services

The Qld distributors will be required to provide auxiliary metering services to support the metering contestability framework along with metering services to support existing type 5 and 6 meters. Distributors hold an electricity distribution authority to provide these metering support services, which creates a regulatory barrier to competition. As a result, we propose to classify them as direct control services.¹⁰⁰ Further, as auxiliary metering services are provided to an identifiable subset of customers, we propose to classify them as alternative control services.¹⁰¹

Some examples include:

- Off cycle meter reads for Type 5 and 6 meters, may include final read – to conduct a final read on removed type 5 metering equipment as required by the Australian Energy Market Operator Service Level Procedure.¹⁰²

⁹⁶ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 3.

⁹⁷ NER, cl. 7.2.3(a)(2).

⁹⁸ NER, cl. 6.2.2(c)(1).

⁹⁹ AER, *Final decision Energex / Ergon Energy 2015–20 regulatory control period, Attachment 13 Classification of services*, April 2015, p. 13-23.

¹⁰⁰ NEL, s. 2F.

¹⁰¹ NER, cl. 6.2.2(c)(5).

¹⁰² This Service Level Procedures applies to Metering Providers who are accredited and registered by AEMO to provide metering services within the National Electricity Market (NEM). The Service Level Procedure details the technical requirements and performances associated with the provision, installation and maintenance of a metering installation. This Service Level Procedures is established under clause 7.14.1A of the NER for the various categories of registration and metering installation types as detailed under clause S7.4 of the NER.

- Change distributor load control relay channel on request that is part of the initial load control installation, nor part of standard asset maintenance or replacement.
- Works to reseal a Type 5 and 6 meter due to customer or third party action.

A detailed list of metering services is contained in appendix C.

Metering coordinator, metering provider, metering data provider

Under the competitive framework for metering, the roles of metering coordinator, metering provider and metering data provider may be performed by any registered person.¹⁰³

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach – with regard to new installations – is to not classify these services.¹⁰⁴ That is, we propose to treat them as unregulated distribution services. From a ring-fencing perspective, the provision of these services will need to be separated from the provision of direct control services if a distributor intends to enter the competitive metering market. We may consider ring-fencing waivers around office and staff sharing obligations where there are no third party competitors (for a time).¹⁰⁵

Importantly, we consider that pre-existing type 5 and 6 metering services, as detailed in appendix C, already encompasses these roles and is reflected in the alternative control service charges.

To explain further, each distributor, as the current 'responsible person' under the NER, was appointed as the metering coordinator as at 1 December 2017.¹⁰⁶ The distributors will remain in this role until such time as the initial type 5 or 6 meter is replaced or the distributor receives a notice from a retailer that it is replacing them as metering coordinator. While a distributor acts as the initial metering coordinator performing its current services like type 5 and 6 meter reading, maintenance and testing, we will classify it as an alternative control service. This approach avoids the need for distributors to incur costs ring-fencing the responsibilities of metering coordinator, when the instances of distributors performing this role will diminish as more type 5 and 6 meters are replaced or retailers exercise their ability to replace distributors as the metering coordinator. We did not receive any submissions on our preliminary position on this issue.

Network metering services

¹⁰³ AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, pp. 127–131.

¹⁰⁴ NER, chapter 10, glossary; *Ergon Energy Corporation Ltd v Australian Energy Regulator* [2012] FCA 393.

¹⁰⁵ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016. CCP sub-panel 10 submitted that the AER should only grant short term waivers in relation to ring-fencing obligations, see: Consumer Challenge Panel (sub-panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 9.

¹⁰⁶ NER, cl. 11.86.7.

This service was formerly known as bulk supply point metering. It refers to the measurement of the flow of energy through the distribution system to support the operation of the wholesale market. The service is often listed in association with the common distribution service. There are no identifiable customers and the distributors are required to provide the service as it plays an important role in network infrastructure. We have uncoupled network metering services from the common distribution service in order to keep similar services grouped together. In doing so we recognise the interdependencies and similarities this service has with activities listed under the common distribution service. Similar to the common distribution service, only the Qld distributors may perform these services in their distribution areas, there are no substitutes and no prospect for the development of competition. As a result, the classification of direct control and further as standard control is appropriate.¹⁰⁷ This is a continuation of the current approach.¹⁰⁸

Network ancillary services

Network ancillary services share the common characteristics of being services provided to individual customers on an 'as needs' basis (e.g. meter testing and reading at a customer's request, moving mains, temporary supply, alteration and relocation of existing public lighting assets). Network ancillary services involve work on, or in relation to, parts of the Qld distributors' respective distribution networks. Therefore, similar to common distribution services, only the relevant distributor may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than the Qld distributors providing network ancillary services in their respective distribution area.¹⁰⁹ Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that the Qld distributors possess significant market power in providing network ancillary services.¹¹⁰

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

Further, we intend to classify network ancillary services as alternative control services because the Qld distributors provide these services to specific customers.¹¹¹ As such, the cost of each network ancillary service is directly attributable to an individual customer.¹¹² This results in costs that are more transparent for customers.

We adopt this view even though network ancillary services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect

¹⁰⁷ NER cl. 6.2.2(c)(1)&(5).

¹⁰⁸ NER cl. 6.2.2(c)(3).

¹⁰⁹ NEL, s. 2F(a).

¹¹⁰ NEL, s. 2F.

¹¹¹ NER, cl. 6.2.2(c)(5).

¹¹² NER, cl. 6.2.2(c)(5) – this includes a small number of identifiable customers.

on the administrative costs to us, the distributors, users or potential users of the network.¹¹³ This is because classifying network ancillary services as alternative control services is consistent with the current approach.

To the extent that the provision of network ancillary services becomes or may become contestable through future changes to the regulatory or contestability frameworks, our proposed alternative control classification would allow distributors to compete as a discrete price for the service is set for each network ancillary service. We did not receive any submissions on our preliminary position to classify network ancillary services as alternative control services.

Ergon Energy and Energex are seeking the reclassification of the 'sale of inventory' service as an alternative control service and its inclusion in the service classification table. Ergon Energy and Energex submitted that they have a ring-fencing waiver for this service and have previously advised us of their intention to seek reclassification.¹¹⁴ We have reviewed the service and are satisfied that it should be classified as a direct control service, with a further classification of alternative control. This service may be subject to some level of competition from potential alternative suppliers, either now or in the future. Furthermore, the service is sought by an identifiable specific subset of users to whom the service is provided. As a result, the classification of alternative control is justified under the Rules.¹¹⁵

Public lighting

The Queensland distributors operate and maintain the majority of public lighting systems throughout Queensland. The distributors provide these services on behalf of local councils and government departments responsible for public lighting in Queensland.

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

- the operation, maintenance, repair and replacement of public lighting assets,
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.¹¹⁶

We also propose to include emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that the Queensland distributors do not provide at the time of our distribution determination. However, emerging public lighting technology may become available during the 2020–25 regulatory control period. We intend to classify public lighting (including emerging public

¹¹³ NER, cl. 6.2.2(c)(2).

¹¹⁴ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 2.

¹¹⁵ NER cl. 6.2.2(c)(1)&(5).

¹¹⁶ AER, *Final framework and approach for Queensland*, April 2014, p. 66; AER, *Final framework and approach for Victoria*, October 2014, p. 62; AER, *Final framework and approach for TasNetworks*, July 2017, p. 28.

lighting technology) as a direct control service and further, as an alternative control service. Our reasons follow.

While the Queensland distributors do not have a legislative monopoly over these services, a monopoly position exists to some extent.¹¹⁷ This is because the Queensland distributors own the majority of public lighting assets.¹¹⁸ 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.¹¹⁹

Based on the above analysis, our proposed approach is to classify public lighting services, including emerging technology, as direct control services.¹²⁰ 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.¹²¹ Our proposed approach is to classify public lighting as an alternative control service for the following reasons:

- Classifying public lighting services as alternative control services provides scope for third parties and new entrants to provide public lighting services for new public lighting assets.¹²²
- Classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future, if the Queensland Government implements a contestability regime. In the meantime, an alternative control classification supports the National Electricity Objective by ensuring distributors provide safe and reliable public lighting services to the community.¹²³
- There would be no material effect on administrative costs to us, the Queensland distributors, users or potential users. This is because we are retaining the current classification.¹²⁴
- The Queensland distributors can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.¹²⁵

¹¹⁷ NEL, s. 2F(d).

¹¹⁸ NEL, s. 2F(a).

¹¹⁹ NEL, s. 2F(a)(d).

¹²⁰ NER, cl. 6.2.1.

¹²¹ NER, cl. 6.2.2(c).

¹²² NER, cl. 6.2.2(c)(1).

¹²³ NER, cl. 6.2.2(c)(1).

¹²⁴ NER, cl. 6.2.2(c)(2).

¹²⁵ NER, cl. 6.2.2(c)(5).

For these reasons, we consider that there is insufficient basis to move away from the presumption that public lighting services in Queensland should be alternative control services.¹²⁶ Energex and Ergon Energy did not comment on our preliminary position to classify public lighting as ACS.

CCP sub-panel 14 supported this classification but were of the view that public lighting should be classified as a negotiated distribution service in the future. CCP sub-panel 14 submitted that Energex and Ergon Energy should be encouraged to address any technical and commercial barriers that preclude the transition of public lighting to a lighter form of regulation in the future. CCP sub-panel 14 opined that public lighting could be considered a negotiated service on the basis that the allocation as a distribution service is largely consequential to the fact that the utilities own the pole to which the light is attached. Further, CCP sub-panel 14 noted that there is a degree of frustration among local councils because:

- public lighting agreements tend to lead to inconsistent performance levels given to some customers;
- contestability for the operation, maintenance and upgrade of existing lights and the provision of new suburban lighting in areas supplied by overhead lines is unlikely in the current regulatory environment due to monopoly ownership of most support structures and exclusions from standard wiring codes; and
- most councils approach public lighting as 'non-core business' and are keen to outsource the responsibility.¹²⁷

We propose to maintain our preliminary position to classify public lighting services as alternative control services given that public lighting customers do not have sufficient countervailing market power. We have concerns about the effectiveness of negotiated services for public lighting and the likelihood that these negotiations will not be successful and will lead to disputes between distributors and customers.

¹²⁶ NER, cl. 6.2.2(c)(3).

¹²⁷ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, pp. 5–6.

Unregulated distribution services

Unregulated distribution services is the term we use to describe distribution services which we have not classified as either direct control or negotiated services.¹²⁸ These services are provided on an unregulated basis and are potentially provided by other service providers in a competitive market. This group of services is particularly important as the number and types of services offered by distributors is growing and changing.

In October 2017, we published the amended Electricity Distribution Ring-fencing Guideline.¹²⁹ Our Ring-fencing Guideline interacts with a number of regulatory instruments, including our service classification decisions. Specifically, our service classification decisions have an impact on how the ring-fencing obligations apply to each distributor for its next regulatory control period.¹³⁰ Under our Ring-fencing Guideline, unregulated distribution services are subject to functional and accounting separation from direct control services. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services. Affiliated entities may provide other electricity services. For the purposes of this final F&A we are not addressing interactions with other regulatory frameworks in detail as these are set out in the explanatory statement to the Ring-fencing Guideline.¹³¹

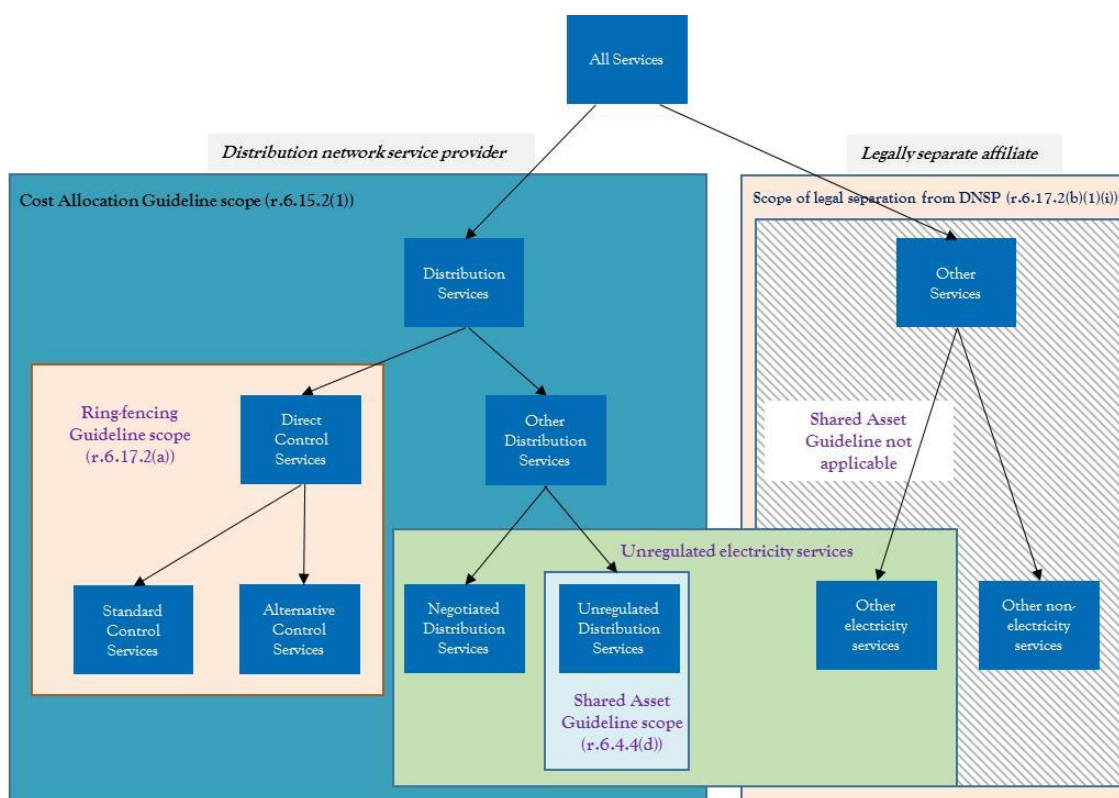
¹²⁸ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

¹²⁹ AER, *Ring-fencing guideline electricity distribution*, October 2017.

¹³⁰ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

¹³¹ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

Figure 1.3 Distribution services linkage to ring-fencing



Source: AER

In approaching classification of unregulated distribution services, distributors (and the AER) are considering if the service would be better treated as a service that is "not classified", and therefore not subject to regulation.

Alternatively, some of these distribution services could be classified as alternative control services. As part of our distribution determination, we would set a cost-reflective price for the service based on information provided by the distributor. Customer uptake of the distributor provided service would depend on whether the price of the service is competitive with that of other market participants. It should be noted that if a service is classified as an alternative control service, it would not be subject to ring-fencing obligations, such as the requirements to use a different brand, to use separate offices and to not share staff. Consequently, there are market effects of classifying a potentially contestable service as an alternative control service rather than an unregulated service.

Developing a comprehensive list of unregulated distribution services will be challenging as this service group will capture all distribution services that are contestable services. This includes all contestable metering and contestable connection services.

Compliance with our Ring-fencing Guideline became mandatory on 1 January 2018. Distributors, when considering what unregulated distribution services they offer, should refer

to the examples contained in the explanatory statement to the Ring-fencing Guideline¹³² and their unregulated revenue streams. For example, a distributor may earn additional revenue from say NBN Co. by permitting NBN Co. to hang its wires from the same poles. The service is 'providing access to electricity poles'. Similarly, some other access to a network asset that forms part of the regulatory asset base (RAB) may be rented to a third party. The service for classification is 'Distribution asset rental', which is an unregulated service.

Given the complexity of the Energy Queensland structure, CCP sub-panel 14 submitted that it is important to ensure the obligations within the Ring-fencing Guideline are rigorously followed, exemptions strictly administered and cost allocation methodology fully transparent and accountable. There should be no perception of Energy Queensland competing for negotiated and unregulated services on an unfair basis with private sector providers of these services.¹³³

Our Ring-fencing Guideline outlines a range of compliance measures to ensure that all DNSPs meet their ring-fencing obligations. Included among these is an annual compliance report, provided by an independent auditor, which it must submit to us after each calendar year. This report, as well as any material breaches of ring-fencing obligations, are published on our website.

Other distribution services previously unregulated

In Appendix B of our preliminary F&A, we proposed to reclassify some services from unregulated to alternative control including network related property services, training third parties for network related access and security lights. QCOSS supported the reclassification of these services, as they require access to the network and cannot be offered by a third party, except with the network's cooperation, and they are provided to specific customers.¹³⁴

¹³² AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, Appendices A and B, pp. 77–86.

¹³³ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 6.

¹³⁴ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, p. 4.

2 Forms of control

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.¹³⁵ This section sets out our decision together with our reasons on the forms of control to apply to Qld distributors' direct control services for the 2020–25 regulatory control period. This section also sets out our proposed approaches on the formulae to give effect to these control mechanisms.

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

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.¹³⁶ Additionally, the formulae that give effect to the control mechanisms in a distributor's regulatory proposal must be the same as the formulae set out in the relevant F&A paper. The formulae cannot be altered between the F&A paper and the making of the determination unless we consider that there has been a material change in circumstances that justifies departing from the formulae set out in that paper.¹³⁷

2.1 AER's proposed approach

Our decision is to apply the following forms of control in the 2020–25 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 mechanisms¹³⁸
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.¹³⁹

¹³⁵ NER, cl. 6.2.5(a).

¹³⁶ NER, cl. 6.12.3(c).

¹³⁷ NER, cl. 6.12.3(c1).

¹³⁸ NER, cl. 6.2.5(b).

¹³⁹ NER, cl. 6.2.6(a).

The NER sets out the form of control mechanisms that may apply to both standard and alternative control services.¹⁴⁰

- a schedule of fixed prices

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

- caps on the prices of individual services (price caps)¹⁴¹

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

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

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

- revenue yield control (average revenue cap)

An average revenue cap is a cap on the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the TAR by a particular unit (or units) of output, usually kilowatt hours (kWh). The distributor complies with the constraint by setting prices so the average revenue is equal to or less than the TAR per unit of output.

¹⁴⁰ NER, cl. 6.2.5(b).

¹⁴¹ 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.

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

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

In making our decision on the control mechanisms for the Qld distributors' standard control services, we have only considered the continuation of the revenue cap, or adoption of price caps or an average revenue cap. We have not considered the other forms of control mechanisms for standard control services based on our previous considerations that they are not superior to either an average revenue cap or a revenue cap in addressing the factors set out in clause 6.2.5(c) of the NER.

We have not considered a schedule of fixed prices. We consider direct price control mechanisms do not provide the level of flexibility within the regulatory control period to manage distribution use of service charges shared across the broad customer base.

We have not considered a WAPC as our previous considerations on this type of control mechanism noted the incentives for distributors to systematically recover revenue above efficient cost recovery resulting in higher bills for consumers.¹⁴² We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹⁴³

We have also not considered a hybrid approach as our previous deliberations considered the higher administrative costs outweigh the potential benefits of this form of control.¹⁴⁴

Our decision on the control mechanisms for the Qld distributors' alternative control services is based on whether there is reason to depart from the current price caps in terms of the factors set out in clause 6.2.5(c) of the NER.

Standard control services

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

- need for efficient tariff structures
- possible effects of the control mechanism on administrative costs to us, the distributor, users or potential users
- regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination

¹⁴² For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

¹⁴³ NEL, s. 7.

¹⁴⁴ For example, see: AER, *Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

- 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.¹⁴⁵

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

Alternative control services

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

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

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

We must state what the basis of the control mechanism is in our distribution determination.¹⁴⁶ This may utilise elements of Part C of chapter 6 of the NER with or without

¹⁴⁵ NER, cl. 6.2.6(a).

¹⁴⁶ NER, cl. 6.2.6(b).

modification. For example, the control mechanism may use a building block approach or incorporate a pass through mechanism.¹⁴⁷

Section 2.3 sets out our consideration of each of the above factors in deciding on the form of control mechanism for alternative control services.

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

Our decision is to maintain a revenue cap for the Qld distributors' standard control services for the 2020–25 regulatory control period. We consider the application of a revenue cap control mechanism best meets the factors set out under clause 6.2.5(c) of the NER.

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

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

CCP sub-panel 14, Ergon Energy and Energex supported maintaining a revenue cap for standard control services.¹⁴⁸ In the absence of network pricing reform, leading to cost-reflective pricing, AGL maintains a preference for price cap control of common distribution services.¹⁴⁹

QCROSS submitted that under a revenue cap, distributors have a clear incentive to overstate demand and associated required capex to maintain the capex once assets are built, rather than the balance of countervailing incentives that applies under a price cap. QCROSS were of the view that a price cap is likely to constrain distributors from spending allowed capex where they see demand could fall, and encourage distributors to estimate demand. Further, QCROSS noted that in relation to incentives for demand management, distributors have not exhibited a tendency to manage demand under revenue caps to date. QCROSS encouraged the AER to conduct a more comprehensive review of the advantages of revenue versus price caps and their related incentives, given that there is an increasingly uncertain environment for forecasting demand.¹⁵⁰ CCP sub-panel 14 also generally encouraged the AER to review the use of revenue caps rather than price caps for standard control

¹⁴⁷ NER, cl. 6.2.6(c).

¹⁴⁸ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 6; Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 3.

¹⁴⁹ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

¹⁵⁰ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, pp. 4–5.

services.¹⁵¹ We note the concerns and agree that a review of the forms of control should be undertaken once we have sufficient historical information to reflect on the performance of revenue caps.

We consider that a revenue cap provides a high likelihood of efficient cost recovery. Under a revenue cap, revenue recovery is fixed and unrelated to energy sales. As pricing reform progresses, more network costs will be recovered through fees such as demand charges and fixed charges which do not rely on energy sales. Energy sales will become less relevant to network cost recovery. Costs for distributors are also largely fixed and unrelated to energy sales. Therefore, our view is that a revenue cap is likely to lead to efficient cost recovery. We also consider that a revenue cap incentivises distributors to reduce their expenditures because their revenues are assured during the regulatory control period. These lower costs can be shared with customers in future regulatory control periods. For example, incentives for non-network or demand management solutions (which may reduce demand) are stronger where revenues are less related to energy sales. Therefore, we consider a revenue cap adequately addresses AGL's concerns that the control mechanism should align prudent expenditure and cost minimisation with maintaining network utilisation.

In contrast, control mechanisms where revenue depends on energy sales (such as price caps) provides distributors with incentives to understate sales forecasts and adjust tariffs to gain revenues above efficient cost levels. This is what we saw when price caps were last in place and influenced the AER to move to revenue caps. A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers. We consider a control mechanism that results in higher bills for consumer than necessary is not consistent with the national electricity objective.¹⁵² In terms of efficient revenue recovery, we consider a revenue cap control mechanism better reflects the NEO than those that rely on energy sales.

Accordingly, we consider that, notwithstanding some desirable theoretical advantages of price caps, revenue caps are still preferred at this stage.

Efficient tariff structures

In deciding on a control mechanism, the NER requires us to have regard to the need for efficient tariff structures.¹⁵³ We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

It is likely that efficient tariff structures can be developed and implemented under all types of control mechanisms. Our recent assessment of distributors' tariff structures has demonstrated that efficient tariff structures have been developed and will be implemented under both average revenue cap and revenue cap control mechanisms. AGL supported this position, however noted that DNSPs' pricing preferences appear to be trending towards

¹⁵¹ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 6.

¹⁵² NEL, s. 7.

¹⁵³ NER, cl. 6.2.5(c)(1).

revenue recovery, because of the form of control, rather than alignment to drivers of network cost.¹⁵⁴

Our previous considerations on the interaction between a control mechanism and its ability to deliver efficient tariff structures during a regulatory control period relied solely on the incentive properties of the different types of control mechanisms.¹⁵⁵ However, recent changes to the NER now require us to undertake a supplementary assessment of the efficiency of a distributor's tariff structures which are set out in a tariff structure statement. Therefore, consideration of the interaction between control mechanisms and efficient tariff structures should also be informed by our assessment of a distributor's tariff structure statement.

The requirement for distributors to prepare tariff structure statements is new. It arises from a significant process of reform to the NER governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- Providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills.
- Transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time.
- Managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

A distributor's tariff structure statement sets out the tariff structures it can apply over a regulatory control period.¹⁵⁶ The tariff structure statement should show how a distributor applied the distribution pricing principles¹⁵⁷ to develop its tariff structures and the indicative price levels of tariffs for the coming five year regulatory control period. The network pricing objective of the distribution pricing principles is the focus for a distributor when developing its network tariffs. The objective is that:¹⁵⁸

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

¹⁵⁴ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

¹⁵⁵ For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 79–81 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy*, 1 July 2014–30 June 2019, March 2013, pp. 76–77.

¹⁵⁶ NER, cl. 6.18.1A(a)(3).

¹⁵⁷ This is a reference to the NER' *pricing principles for direct control services*, alternatively described in this paper as the "distribution pricing principles"; NER, cl. 6.18.5(e)–(j).

¹⁵⁸ NER, cl. 6.18.5(a).

We must approve a tariff structure statement unless we are reasonably satisfied it will not comply with the distribution pricing principles or other relevant requirements of the NER.¹⁵⁹

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

Through the initial tariff structure statements many distributors will be introducing more cost reflective tariff structures, such as demand based tariffs. In our assessment we found no evidence to suggest that Evoenergy's average revenue cap or other distributors' revenue caps inhibited the ability to develop or implement efficient tariff structures. Therefore, we consider that efficient tariff structures can occur under both average revenue cap and revenue cap control mechanisms. On this basis, we also consider efficient tariff structures are likely to occur under all forms of control mechanisms, including price caps.

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

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

Administrative costs

In deciding on a control mechanism, the NER requires us to have regard to the possible effects of the control mechanism on administrative costs.¹⁶⁰ We consider, where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor and users.

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

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

¹⁵⁹ NER, cl. 6.12.3(k).

¹⁶⁰ NER, cl. 6.2.5(c)(2).

Existing regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements applicable to the relevant service immediately before the commencement of the distribution determination.¹⁶¹ We note maintaining a revenue cap control mechanism for the Qld distributors' standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(3) of the NER than an alternative control mechanism.

AGL submitted that our position, namely, that under a revenue cap there is no additional administrative costs and a revenue cap allows for consistency between regulatory periods, is valid, but is not an overriding argument given that the AER has overseen many networks transitioning from price to revenue caps in recent determinations.¹⁶² We consider that the ability to transition between control mechanisms demonstrates that consistency between periods is not the sole criteria for assessing the appropriate control mechanism, but neither does it remove it as a consideration. In response to AGL's submission, we refer to our earlier discussion of revenue caps compared to price caps under section 2.3.

Desirability of consistency between regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the desirability of consistency between regulatory arrangements for similar services both within and beyond the relevant jurisdiction.¹⁶³ We consider the continuation of a revenue cap control mechanism for the Qld distributors' standard control services delivers consistent regulatory arrangements for these services across jurisdictions.

Apart from Evoenergy (formerly ActewAGL), all other electricity distributors who are currently subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. However, we have decided to apply a revenue cap to Evoenergy's standard control services for the 2019–24 regulatory control period.¹⁶⁴ This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore, maintaining the Qld distributors' revenue cap control mechanism will ensure consistent regulatory arrangements for these services across jurisdictions. For these reasons, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(4) of the NER than an alternative mechanism.

Revenue recovery

We consider that a control mechanism should give a distributor an opportunity to recover efficient costs. Also, a control mechanism should limit revenue recovery above such costs.

¹⁶¹ NER, cl. 6.2.5(c)(3).

¹⁶² AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

¹⁶³ NER, cl. 6.2.5(c)(4).

¹⁶⁴ ActewAGL Distribution, *Response to AER preliminary framework and approach*, April 2017, p. 11.

Revenue recovery above efficient costs results in higher prices for end users. Further, allocative efficiency is reduced when a distributor recovers additional revenue from price sensitive services through prices above marginal cost.¹⁶⁵

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

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

In contrast, control mechanisms where revenue depends on energy sales (such as average revenue caps or price caps) provides distributors with incentives to understate sales forecasts and adjust tariffs to gain revenues above efficient cost levels.¹⁶⁶ A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.¹⁶⁷ We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹⁶⁸

In terms of efficient revenue recovery, we consider a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.¹⁶⁹

AGL submitted that our review of the form of control focuses on the revenue determination process rather than DNSP behaviour during the period. AGL argued that the determination process only estimates efficient cost and will be in error. AGL prefers a control that limits the price to customers rather than focussing on limiting revenue with the potential for significant price increases.¹⁷⁰ As discussed in section 2.3, we consider that revenue caps and price caps both incentivise DNSPs to different behaviours. On balance, we consider a revenue cap to be the more appropriate option.

Pricing flexibility and stability

Price flexibility enables a distributor to restructure its tariffs to meet changes in the environment of operating an electricity distribution network during a regulatory control period. Price stability is important because it affects retailers' ability to manage risks incurred from

¹⁶⁵ 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.

¹⁶⁶ For example, see: AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67.

¹⁶⁷ For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

¹⁶⁸ NEL, s. 7.

¹⁶⁹ NEL, s. 7.

¹⁷⁰ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

changes to network tariffs, which they then package into retail plans for customers. It also affects customers' ability to manage their bills.

We consider price flexibility is primarily influenced by the distribution pricing principles and the side constraint.¹⁷¹ Therefore, price flexibility is similar for all control mechanisms as they are subject to the same distribution pricing principles and the same side constraint.

In terms of price stability, some control mechanisms are more likely to deliver stable prices than others. However, price instability can occur under all control mechanisms because the NER requires various annual price adjustments regardless of the control mechanism.¹⁷²

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

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

We have attempted to reduce the significance of this issue in our recent determinations by applying a rolling unders and overs account which includes an additional true up for the estimated under and over recovery of revenues for the year in between (year $t-1$).¹⁷³ The inclusion of this estimated year helps smooth year-on-year revenue and tariff adjustments because the effects of the estimated year $t-1$ under or over recovery will have been largely accounted for by the second year after the under (over) recovery was incurred. That is, more frequent annual adjustments can alleviate the potential for price instability created by the 2 year lag. When year $t-1$ becomes year $t-2$ the adjustment to the TAR will only need to account for the difference between the estimated and actual under or over recovery and not the overall total under or over recovery.

In terms of stability across regulatory control periods, we consider an average revenue cap or a price cap can result in greater price volatility compared to a revenue cap.¹⁷⁴ This issue

¹⁷¹ Clause 6.18.6(b) of the NER requires the expected weighted average revenue to be raised from a Standard Control Services tariff class to not exceed the corresponding expected weighted average revenue from the preceding year by more than a permissible percentage (the tariff side constraint).

¹⁷² These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from transmission network service providers.

¹⁷³ For example, see: AER, *Final Decision, CitiPower distribution determination 2016 to 2020: Attachment 14—Control mechanisms*, May 2016, Appendix A, pp. 18–19.

¹⁷⁴ AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing*

is particularly pronounced if a trend of falling demand and consumption has set in throughout the regulatory control period. This scenario would prompt a large upward adjustment in the X-factors (and hence prices) for the next regulatory control period under an average revenue cap. In contrast, the volume forecasts are updated annually under a revenue cap. This would mean that prices would rise gradually over the regulatory period (rather than jump up at the end of the period) if a trend of falling demand was evident.

AGL submitted that this argument assumes that efficient network prices would need to increase significantly in the next period in line with the fall in demand and consumption. AGL would hope that if network utilisation fell markedly, then other cost components would also be re-examined by the AER. AGL submitted that revenue cap control simply ensures DNSPs recover a forecast of network revenue.¹⁷⁵

On balance, when weighing price flexibility and stability along with the other factors we have considered, our decision is to maintain the Qld distributors' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling unders and overs account reduces the magnitude of this effect.

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.¹⁷⁶ Where prices are cost reflective, consumers and providers of demand side management face efficient incentives because they can take into account the cost of providing the service in decision making.

Under a revenue cap, a distributor's revenue is fixed over the regulatory control period. A distributor can therefore improve its financial position by reducing costs. This creates an incentive for a distributor to undertake demand side management projects that reduce total costs, even if that means the distributor does not build new assets or replace existing ones.¹⁷⁷ We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales, such as in a price cap.

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

¹ July 2014, pp. 67–69.

¹⁷⁵ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

¹⁷⁶ Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

¹⁷⁷ That is, demand side management projects that result in a reduction in future network expenditure greater than the cost of implementing the demand side management projects.

AGL agreed that there is more incentive for DNSPs to undertake demand side management projects that reduce costs because revenue is unaffected. However, AGL submitted that this position has not been supported by DNSP behaviour to date, as conceded by the AER though introduction of schemes to incentivise DNSPs' use of demand management response.¹⁷⁸

Notwithstanding AGL's comments throughout section 2.3, AGL conceded that moving to cost-reflective network pricing will both diminish the advantages of price cap regulation whilst reducing the problems with revenue cap control. AGL submitted that if we maintain a revenue cap control in the next regulatory control period, then it needs to be accompanied by the requisite network pricing reform.¹⁷⁹

Formulae for control mechanism

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for standard control services in the F&A paper.¹⁸⁰ In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.¹⁸¹ Below is the proposed formula to apply to the Qld distributors' standard control services revenues. We consider that the formula gives effect to the revenue cap. Ergon Energy and Energex support the proposed formula.¹⁸²

Figure 2.1 Revenue cap formula to be applied to the Qld distributors' standard control services

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

where:

TAR_t is the total allowable revenue in year t.

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

¹⁷⁸ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 3.

¹⁷⁹ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 4.

¹⁸⁰ NER, cl. 6.8.1(b)(2)(ii).

¹⁸¹ NER, cl. 6.12.3(c1).

¹⁸² Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 4.

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

t is the regulatory year.

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

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

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

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

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

S_t is the s-factor for regulatory year t.¹⁸³ As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.¹⁸⁴

However, we are currently undertaking a review of the STPIS. How the s-factor will apply within the revenue cap formula may depart from the current arrangements. Depending on the outcome of our review, provision to adjust revenues for performance against the STPIS may be made through either the S or I factors as set out in this final F&A paper. If the review is completed in time, the distributors may need to apply the revised STPIS for the 2020–25 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹⁸⁵ from the December quarter in year $t-2$ to the December quarter in year $t-1$, calculated using the following method:

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

¹⁸³ The meaning for year “t” under the price control formula is different to that in Appendix C of STPIS. Year “t+1” in Appendix C of STPIS is equivalent to year “t” in the price control formula of this decision.

¹⁸⁴ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

¹⁸⁵ If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

divided by

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

minus one.

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

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

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

Our proposed approach is to apply caps on the prices of individual services (price caps) in the 2020–25 regulatory control period to all of the Qld distributors' alternative control services. We propose classifying the following services as alternative control services:

- type 5 and 6 metering services (legacy meters)
- public lighting services
- ancillary services.

We note the Qld distributors' alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2020–25 regulatory control period best meets the factors set out under clause 6.2.5(d) of the NER.

CCP sub-panel 14, Ergon Energy and Energex supported the decision to apply price caps to alternative control services.¹⁸⁶

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.¹⁸⁷ For example, the price caps could be based on a building block approach, or a modified building block cost build up. We have set out our proposed formulae that will give effect to the price cap control mechanisms in figure 2.2 and figure 2.3 below. However, it is at the distributor's discretion as to the approach it undertakes to develop its initial prices.

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

¹⁸⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 6; Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 3.

¹⁸⁷ NER, cl. 6.2.6(c).

once it knows the scope of the work. Because of this uncertainty, our proposed price cap formula for quoted services differs to that proposed to apply to metering and fee based services. Our quoted services price cap is consistent with the approach we have adopted in the past.

A further consideration relates to the treatment of new services that might be offered by Energex and Ergon Energy within the regulatory control period. Where such services were not identified at the time of the AER's determination but for which the service clearly falls within one of the established service groupings, we propose that a quoted price approach be adopted based on a similar service within that same service grouping. For example, the price for a new type of security lighting would be set based on the same approach as a similar security lighting service. This approach would give the distributors additional flexibility to introduce new services while offering consumers the protections associated with price regulation. If there was no other similar service, the new service would be unregulated and may therefore be subject to ring-fencing restrictions that affect the use of the Qld distributor's brands as well as sharing of staff and offices in offering the new services.

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

Our consideration of the relevant factors is set out below.

Influence on the potential to develop competition

We consider a departure from the current price cap controls for the Qld distributors' alternative control services would not have a significant impact on the potential development of competition. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 discusses service classification.

Administrative costs

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

Existing regulatory arrangements

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

Desirability of consistency between regulatory arrangements

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

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

Cost reflective prices

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

Formulae for alternative control services

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for alternative control services.¹⁸⁸ In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that a material change in circumstances justifies departing from the formulae as set out in the F&A paper.¹⁸⁹

Below are our proposed price cap formulae which will apply to the Qld distributors' alternative control services. Ergon Energy and Energex supported the proposed control formulae.¹⁹⁰

Figure 2.2 Price cap formula to be applied to the Qld distributors' legacy metering, public lighting and ancillary services (fee based)

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

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

Where:

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

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

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

¹⁸⁸ NER, cl. 6.8.1(b)(2)(ii).

¹⁸⁹ NER, cl. 6.12.3(c1).

¹⁹⁰ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 4.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities¹⁹¹ from the December quarter in year $t-2$ to the December quarter in year $t-1$, calculated using the following method:

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

divided by

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

minus one.

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

X_t^i is the X factor for service i in year t . The X factors are to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

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

Figure 2.3 Price cap formula to be applied to the Qld distributors' quoted services

Price = Labour + Contractor Services + Materials

Where:

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹⁹² from the December quarter in year $t-2$ to the December quarter in year $t-1$, calculated using the following method:

¹⁹¹ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

¹⁹² If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

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

divided by

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

minus one.

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

X_t^i is the X factor for service i in year t. The X factor is to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

3 Incentive schemes

This chapter sets out our proposed application of a range of incentive schemes to the Qld distributors for the 2020–25 regulatory control period. At a high level, our proposed approach is to apply the:

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

QCOSS submitted that it would prefer the AER to apply a mix of incentives and penalties to distributors rather than a set of incentive arrangements alone. QCOSS were of the view that there are effectively no penalties for distributors who underspend their allowed revenue.¹⁹³ We disagree with this view as the incentive schemes already incorporate both incentives and penalties. CCP sub-panel 14 supported the application of these incentive schemes, provided the network is showing it is efficient.¹⁹⁴ CCP sub-panel 14 were of the view that a high level of scrutiny is required in assessing efficiency of the base year and current performance in relation to the incentive schemes. Their comments were particularly directed toward the unique organisational structure of Energy Queensland and related businesses, especially in relation to cost allocation, sharing of resources and intellectual property, emergency support arrangements and shared services arrangements, in addition to the fact that the companies are undergoing significant organisational change.¹⁹⁵ Ergon Energy and Energex also supported the application of these incentive schemes.¹⁹⁶

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 distribution STPIS¹⁹⁷ provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards

¹⁹³ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, p. 5.

¹⁹⁴ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 7.

¹⁹⁵ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 2.

¹⁹⁶ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 4.

¹⁹⁷ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009. Currently under review, however the amendment process is not yet complete.

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 customers¹⁹⁸ experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.¹⁹⁹

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

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

The Qld distributors may propose to vary the application of the STPIS in their respective regulatory proposals.²⁰⁰ We can accept or reject the proposed variation in our determination. Each year we will calculate the Qld distributors' s-factor based on service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.²⁰¹ A distributor proposing a delay must provide in writing its reasons and justification as to why a delay will result in reduced price variations to customers.

¹⁹⁸ Except where a jurisdictional electricity GSL requirement applies.

¹⁹⁹ 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.

²⁰⁰ AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.2.

²⁰¹ AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.5(d) and (e).

Our STPIS currently applies to the Qld distributors. Based on stakeholders' recommendations, we applied a lower level of financial risk to the distributors in terms of a penalty or reward of ± 2 per cent through an s-factor adjustment to the allowable revenue. GSLs are provided for through the Queensland Competition Authority GSL scheme, so the GSL component of our scheme does not apply.

AER's proposed approach

Our proposed approach is to continue to apply the national STPIS to the Qld distributors in the 2020–25 regulatory control period. We propose to:

- set revenue at risk for each distributor at ± 2 per cent
- segment the network according to the four STPIS feeder categories (CBD, urban, short rural and long rural) as per the scheme's definitions
- apply the system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI) and customer service (telephone answering) parameters
- set performance targets based on the distributors' average performance over the past five regulatory years
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the method and value of customer reliability (VCR) values as indicated in AEMO's 2014 Value of Customer Reliability Review final report.

We will not apply the GSL component if the Qld distributors remain subject to a jurisdictional GSL scheme. This is supported by QCOSS, however QCOSS asked the AER to compare the GSL Scheme with that regulated by the Queensland Competition Authority to identify any inconsistencies between the schemes.²⁰²

We are currently undertaking a review of the STPIS. If the review is completed in time, Qld distributors may need to apply the revised STPIS for the 2020–25 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

In the preliminary F&A, we proposed to increase the revenue at risk to ± 5 per cent. Ergon Energy and Energex were strongly against the increase in revenue at risk from ± 2 per cent to ± 5 per cent. Ergon Energy and Energex submitted that since the inception of the STPIS, they have outperformed the STPIS targets and delivered improved reliability and customer service outcomes with a lower revenue of risk and therefore, did not consider that a high-powered STPIS was necessary. Ergon Energy and Energex submitted that a high-powered STPIS increases the risk of within-period revenue volatility which potentially exacerbates

²⁰² Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, p. 6.

affordability issues.²⁰³ The Electrical Trades Union (ETU) also expressed concerns with the increase noting that Ergon Energy and Energex have consistently achieved the performance requirement under the current target in the current regulatory period. The ETU expressed concerns that a change to the STPIS target will result in unintended consequences, such as inefficient work practices, leading to higher costs to consumers.²⁰⁴

QCOSS supported the application of the scheme however did not support increasing the revenue at risk from ± 2 per cent to ± 5 per cent. QCOSS were of the view that it should be up to Ergon Energy and Energex to demonstrate that customers would be willing to pay 5 per cent more for an improvement in reliability.²⁰⁵

However, CCP sub-panel 14 strongly supported the proposed application of the maximum factor of ± 5 per cent, noting that incorporation of an enhanced scheme which reflects new and high-impact ways that utilities interact with customers and communities should be encouraged.²⁰⁶ AGL also supported the application of the scheme and the approach to base performance targets on the DNSP's average performance over recent years.²⁰⁷

We raised the prospect of ± 5 per cent in the preliminary F&A to seek stakeholders' views. The purpose of the STPIS is to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality. Given the very strong performance of the networks in recent years, we consider that a stronger incentive in Queensland is not required at the present moment.

AER's assessment approach

In deciding how to apply the current STPIS scheme we have considered the requirements of the NER. The NER sets out certain requirements in relation to developing and implementing a STPIS.²⁰⁸ 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.

²⁰³ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 5.

²⁰⁴ Electrical Trades Union, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 2.

²⁰⁵ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, p. 6.

²⁰⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 11.

²⁰⁷ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 4.

²⁰⁸ NER, cl. 6.6.2(b).

Benefits to consumers

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

We considered the benefits to consumers of applying the STPIS when we developed the scheme. These considerations are set out in our final decision for the distribution STPIS.²⁰⁹

Reasons for AER's proposed approach

Our reasons for applying the STPIS to 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 by the Electricity Industry Code. Our proposed approach to applying the STPIS in Qld is to not create duplication or compromise Qld distributors' ability to comply with the jurisdictional requirements. Our proposed approach is therefore to not apply the GSL component of our national STPIS while the GSL arrangements in Qld remain in place. We will amend this position if the Qld Government advises that these arrangements will cease to apply.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.²¹⁰

²⁰⁹ AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

²¹⁰ NER, cl. 6.6.2(b)(3)(vi).

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

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.²¹¹

In September 2014, AEMO completed analysis of the VCR across the NEM.²¹² We stated in our final decision for NSW distributors' 2015–19 regulatory period and our final F&A for NSW distributors' 2019–24 regulatory period,²¹³ that we will apply the latest value for VCR through the distribution determination in calculating the incentive rates. This is because we consider the 2014 AEMO NSW and ACT VCR better reflects the willingness of customers to pay for the reliable supply of electricity in the Qld. We consider that this approach is still appropriate.

Incentive rates will be calculated at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

Our proposed approach is to maintain the level of revenue at risk for Qld distributors at ± 2 per cent. This is because we do not consider a stronger incentive in Qld is required given the very strong performance of the networks in recent years, which reflects the high investment in Qld over previous periods.

Balanced incentives

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

Defining performance targets

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

The NER requires us to consider past performance of the distributor's network in developing and implementing the STPIS.²¹⁴ Our preferred approach is to base performance targets on the Qld distributors' average performance over the past five regulatory years.²¹⁵ Using an

²¹¹ 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.

²¹² AEMO, *Value of customer reliability review - Final report*, September 2014.

²¹³ AER, *Final framework and approach for NSW distributors 2019-24*, July 2017, p. 63.

²¹⁴ NER, cl. 6.6.2(b)(3)(iii).

²¹⁵ Subject to any modifications required under cl. 3.2.1(a) and (b) of the national STPIS.

average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in a specific year to make future targets less onerous.

Under this approach, distributors will only receive a financial reward for achieving reliability improvements. More importantly, a distributor can only retain the reward if it can maintain the reliability improvements. This is because once an improvement is made, the benchmark performance targets will be adjusted to reflect the improved level of performance. If it allows reliability to decline in the future, the distributor will be penalised. Our STPIS limits variability in penalties and rewards caused by circumstances outside the distributor's control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance.

Interactions with our other incentive schemes

In applying the STPIS, we must consider any other incentives available to the distributor under the NER or relevant distribution determination.²¹⁶ In Qld, the STPIS will interact with our expenditure and demand management incentive schemes.

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

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.²¹⁷

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

3.2 Efficiency benefit sharing scheme

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

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

²¹⁶ NER, cl. 6.6.2(b)(3)(iv).

²¹⁷ Included in the distributor's approved forecast capex for the next period.

This section sets out our proposed approach and reasons on how we intend to apply the EBSS to the Qld distributors in the 2020–25 regulatory control period.

AER's proposed approach

We intend to apply the EBSS to the Qld distributors in the 2020–25 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers.²¹⁸ This will occur only if the opex forecast for the following period is based on the distributors' revealed costs. Our distribution determinations for the Qld distributors for the 2020–25 regulatory control period will specify if and how we will apply the EBSS.²¹⁹

AER's assessment approach

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between a network service provider and network users.²²⁰ We must also have regard to the following factors in developing and implementing the EBSS:²²¹

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

Reasons for AER's proposed approach

The EBSS applies to the Qld distributors in the 2015–20 regulatory control period.

We will decide if and how we will apply the EBSS to the Qld distributors in the 2020–25 regulatory control period in our determinations. The decision to apply the EBSS will depend on whether we expect to use the distributors' revealed costs in the 2020–25 regulatory control period to forecast opex in the following period.

Why we would apply the EBSS

We will only apply the EBSS in the 2020–25 regulatory control period if we expect we will use a revealed cost forecasting approach to forecast opex for the 2025–30 regulatory control period.

²¹⁸ NER, cl. 6.5.8(a).

²¹⁹ AER, *Efficiency benefit sharing scheme*, 29 November 2013.

²²⁰ NER, cl. 6.5.8(a).

²²¹ NER, cl. 6.5.8(c).

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

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

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

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

In implementing the EBSS we also consider any incentives distributors may have to capitalise expenditure.²²² Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. If the CESS and EBSS are both applied, these incentives will be relatively balanced. We discuss the CESS further in section 3.3.

We also consider the effects of implementing the EBSS on incentives for non-network alternatives²²³ (which are generally opex rather than capex). When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor will receive a net reward for implementing the non-network alternative.²²⁴ Non-network alternatives and the demand management incentives, including the new DMIS, are discussed further in section 3.4.

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

222 NER, cl. 6.5.8(c)(4).

223 NER, cl. 6.5.8(c)(5).

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

CCP sub-panel 14 supported the application of the EBSS so long as the revealed costs in the Energex and Ergon Energy proposed base year are shown to be efficient.²²⁵ However, CCP sub-panel 14 stated that we should exercise caution in using the revealed costs in any year of the current period as the basis to forecast opex for the 2020–25 period. It considered we should only apply the EBSS to Energex and Ergon Energy when they have achieved an efficient level of opex. CCP sub-panel 14 stated that we should not use the EBSS to fund Energex and Ergon Energy's 'transition' to efficient opex levels.

We note that CCP sub-panel 14 is correct that if a distributor's revealed opex is not efficient when we start to apply the EBSS, the scheme will share the distributor's opex overspend as it transitions to an efficient level. The application of the EBSS would result in the network service provider incurring only approximately 30 per cent of its opex overspend during the transition to efficient opex. We will take this into consideration when we decide if and how we will apply the EBSS to the Qld distributors.

Ergon Energy and Energex supported the application of the EBSS.²²⁶

AGL also expressed support for the application of the scheme only if we are satisfied that the scheme will provide benefits to consumers and use the distributors' revealed costs. However, AGL contended that the scheme will provide no benefit to consumers.²²⁷ We consider that the EBSS is an important means of supporting the incentive-based approach to regulation embodied in the NER. We consider that the EBSS provides a continuous incentive for businesses to seek efficiencies across the regulatory control period and supports the use of revealed costs to forecast opex. Electricity distributors appear to have improved their opex productivity performance in recent years and we will pass these productivity gains on to consumers through our revealed cost opex forecasting approach, supported by the EBSS.

Why we would not apply the EBSS

We will not apply the EBSS if it is likely we will *not* use a revealed cost forecasting approach to forecast opex for the 2025–30 regulatory control period.

If we apply the EBSS but do not forecast opex using revealed costs, a distributor could in theory receive an EBSS reward for efficiency gains (at a cost to consumers), but consumers would not benefit through a lower revealed cost forecast. If the distributor expects this, it has an incentive to increase its EBSS carryover by underspending in its base year, knowing the underspend will not reduce its opex forecast.²²⁸ Consumers would pay the EBSS reward but not receive a share of the underspend and would be worse off. This outcome is contrary to

²²⁵ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 8.

²²⁶ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 4.

²²⁷ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 5.

²²⁸ In our explanatory statement to the EBSS, we discuss why we should exclude the expenditure categories not forecast using a single year revealed cost forecasting method from the EBSS to prevent network users being worse off. AER, *Explanatory statement - efficiency benefit sharing scheme*, November 2013, pp. 18-19.

the NER, which requires that the EBSS must provide for a fair sharing of efficiency gains and losses between a distributor and consumers.²²⁹

If a distributor's revealed costs in the 2015–20 regulatory control period are materially higher than the opex incurred by a benchmark efficient distributor, we will be unlikely to use revealed costs to forecast opex for the 2020–25 regulatory control period. In which case, we will be unlikely to apply the EBSS.

3.3 Capital expenditure sharing scheme

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

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend amount for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts.²³⁰ We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added to or subtracted from the distributor's regulated revenue as a separate building block in the next regulatory control period.

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

AER's proposed approach

²²⁹ NER, cl'6.5.8(a).

²³⁰ 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.

Our proposed approach is to apply the CESS, as set out in our capex incentives guideline,²³¹ to the Qld distributors in each regulatory year of the 2020–25 regulatory control period.

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:²³²

- make that decision in a manner that contributes to the capex incentive objective set out in the NER²³³
- consider the CESS principles,²³⁴ capex objectives,²³⁵ 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.

Reasons for AER's proposed approach

We propose to apply the CESS to the Qld distributors in the 2020-25 regulatory control period as we consider this will contribute to the capex incentive objective.

The Qld distributors are currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.²³⁶ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.²³⁷ We are also proposing to apply forecast depreciation, which we discuss further in chapter 5. In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the STPIS and DMIS.

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

²³¹ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

²³² NER, cl. 6.5.8A(e).

²³³ NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

²³⁴ NER, cl.6.5.8A(c).

²³⁵ NER, cl. 6.5.7(a).

²³⁶ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

²³⁷ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.²³⁸ Because of this a distributor may choose to spend capex earlier, or spend on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

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

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

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

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

QCOSS submitted that the CESS only works if we can accurately forecast demand and actual capex otherwise there is an incentive to overstate demand and hence greater forecast capex. QCOSS were of the view that this allows for a windfall to the distributor when there is an underspend and distributors can keep 30 per cent of the difference in the next regulatory period. The DMIS provides incentives to install demand management instead of spending

²³⁸ 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.

capital on the network and QCOSS submitted that there should be an adjustment to either the CESS or DMIS to avoid providing rewards under both schemes when there is a capital underspend.²³⁹ We do not agree that the CESS and DMIS provide a double reward in these circumstances, the schemes have different purposes and target different behaviours/incentives.

CCP sub-panel 14 were of the view that rather than an automatic application of CESS to Energex and Ergon Energy, we should carefully examine the reasons for the capital underspend to assess whether there should be an adjustment for deferral of capex as provided for in the CESS guideline.²⁴⁰ Recent analysis by the Centre for Efficiency and Productivity Analysis (CEPA) of periods prior to the introduction of the CESS showed a consistent underspend of allowed capex, particularly from Energex and Ergon Energy.²⁴¹ CCP sub-panel 14 argued that there are no legitimate reasons for the network to share in the CESS benefits.²⁴²

Ergon Energy and Energex expressed concern with the issue of adjusting rewards for capital expenditure deferrals as it is unclear how we will make adjustments and identify deferred projects.²⁴³ We anticipate that we would identify any significant deferrals through our ex post assessment of actual capex in the current regulatory control period. We will only apply an adjustment to the CESS payments where a DNSP has deferred capex in the current regulatory control period and:

- a. the amount of the deferred capex in the current regulatory control period is material; and
- b. the amount of the estimated underspend in capex in the current regulatory control period is material; and
- c. total approved forecast capex in the next regulatory control period is materially higher than it is likely to have been if a material amount of capex was not deferred in the current regulatory control period.

AGL did not support the CESS and submitted that the CESS cannot demonstrate any long-term benefits to consumers. AGL argued that the requirement for a CESS indicates that we believe these incentives are not enough to avoid DNSPs investing in inefficient or imprudent capital. In AGL's experience, many privately owned DNSPs have acted commercially and chosen to not spend expected capital allowance because of the incentives already inherent in the regulatory framework, without the need for a capital based incentive scheme. AGL

²³⁹ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May 2018, p. 7.

²⁴⁰ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 10.

²⁴¹ CEPA, "Incentives Faced by Network Service Providers", Report to AEMC, 16 April 2018 Draft Report pp 34–5, <https://www.aemc.gov.au/sites/default/files/2018-04/CEPA%20AEMC%20CapexBias%20Report%20DRAFT.pdf>.

²⁴² Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 10.

²⁴³ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, pp. 6–7.

submitted that customers paying for inefficient or imprudent capital investment is not acceptable but requiring customers to pay additional revenue simply to avoid even greater and longer term payments is a second best option.²⁴⁴ We consider that each of the incentive schemes are designed to work together to provide a constant and balanced incentive to improve performance and reduce expenditure. We are only now starting to see outcomes from the CESS, which we continue to monitor. If we find that the CESS is leading to unintended outcomes, we will consider refining or redesigning the scheme to ensure it produces long-term benefits to consumers.

3.4 Demand management incentive scheme and demand management innovation allowance mechanism

We established a new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) in December 2017.²⁴⁵ It is intended that the new DMIS and DMIA are to apply to the Qld distributors in the 2020–25 regulatory control period.

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

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

Reasons for AER's proposed approach

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

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

²⁴⁴ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, pp. 4–5.

²⁴⁵ See <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>.

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

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

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

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

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

We believe that the DMIS, supported by DMIA, will provide long term benefits to customers.

AER's proposed position

We intend to apply our new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) as published by us in December 2017 to Energex and Ergon Energy in the 2020–25 regulatory control period.

CCP sub-panel 14, Ergon Energy and Energex supported the application of the DMIS.²⁴⁶ CCP sub-panel 14 encouraged us to emphasise the importance of the recently updated DMIS and DMIA incentive schemes to the Energex and Ergon Energy proposals, in particular the opportunity for operating cost trade-offs to capital investment in long-lived

²⁴⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 11; Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 4.

assets.²⁴⁷ AGL submitted that it was hopeful the DMIS and DMIA are successful in encouraging DNSPs to utilise non-network solutions that are lower cost to investing in network assets.²⁴⁸ When establishing the DMIS and DMIA, AGL would support the AER communicating clearly its expectations on how the DNSPs select relevant projects and that it enables third parties to propose and implement demand management solutions.²⁴⁹

AER's assessment approach to the DMIS

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

We consider the new DMIS is designed to provide higher incentives for the distributors and consumers to adopt more demand management measures, which should put greater downward pressure on prices, benefitting the whole community. Along with the new DMIS, we have improved its current research and development fund—the DMIA. The improved allowance provides more funding to networks to undertake further research on demand management initiatives and to share these learnings across industry and consumers.

We will undertake annual compliance assessment of distributors' demand management compliance report in accordance with the criteria set out in the DMIS and DMIA, to ensure the benefits realised from the demand management are delivered to the consumers. We will reject claims that do not meet the criteria under the DMIS or DMIA.

²⁴⁷ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 11.

²⁴⁸ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 4.

²⁴⁹ AGL Energy Limited, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 21 May 2018, p. 5.

4 Expenditure forecast assessment guideline

This chapter sets out our intention to apply our expenditure forecast assessment guideline (the EFA guideline)²⁵⁰ including the information requirements applicable to Qld distributors for the 2020–25 regulatory control period. The EFA guideline sets out our expenditure forecast assessment approach developed and consulted upon during the Better Regulation program. It outlines the assessment techniques we will use to assess a distributor's proposed expenditure forecasts, and the information we require from the distributor.

The EFA guideline uses a nationally consistent reporting framework that allows us to compare the relative efficiencies of distributors and decide on efficient expenditure forecasts. The Queensland distributors advised us on 29 June 2018 of the methodology they propose to use to prepare their forecasts, in accordance with the NER.²⁵¹ In the final F&A we must advise whether we will deviate from the EFA guideline.²⁵² This will provide clarity on how we will apply the EFA guideline and the information the Qld electricity distributors should include in their regulatory proposals. This contributes to an open and transparent process and makes our assessment of expenditure forecasts more predictable. The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of the expenditure forecasts that distributors include in their regulatory proposals. We intend to have regard to the assessment tools set out in the guideline. The tool kit includes:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.²⁵³

We exercise judgement to determine the extent to which we use a particular technique to assess a regulatory proposal. We use the techniques we consider appropriate depending on the specific circumstances of the determination. The guideline is flexible and recognises that we may employ a range of different estimating techniques to assess an expenditure forecast.

For opex, in most cases we take a base-step-trend approach to assessing forecast expenditure and in this context use top down economic benchmarking tools to determine the reasonableness of the forecast rather than a bottom-up assessment approach. However, in

²⁵⁰ We were required to develop the EFA guideline under clauses 6.4.5 and 11.53.4 of the NER. We published the guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

²⁵¹ NER, cl. 6.8.1A(b)(1).

²⁵² NER, cl. 6.8.1(b)(2)(viii).

²⁵³ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

exercising our judgement, we may use any analytical tool at our disposal, including assessing individual elements of the forecast using a bottom-up approach.

We will continue to develop and use economic benchmarking to inform our expenditure decisions consistent with the EFA guideline. Economic benchmarking remains a tool in assessing the relative efficiency of network services providers. We are likely to use a range of benchmarking approaches in assessing expenditure forecasts. Benchmarking also provides a source of information to assist both service providers and other interested parties about the relative productivity of individual businesses and the trends in productivity for the industry.

In the context of continuously improving economic benchmarking, we are currently reviewing and refining our analysis of operating environment factors in consultation with industry and other interested parties. The consultation with industry is ongoing and we are looking to finalise the review mid-2018.²⁵⁴ We will then seek to implement any recommended improvements from that process in our annual benchmarking and regulatory determination processes.

We received one submission on our approach to apply the EFA guideline from CCP sub-panel 14, who supported the application of the guideline. CCP sub-panel 14 noted the complex company structure of Ergon Energy and Energex (Energy Qld) and encouraged the AER to use a broad suite of measures to ascertain whether the networks' revealed costs are in fact an indication that it is operating at the level of a benchmark efficient entity.²⁵⁵ Consistent with the approach outlined above, we will use top down economic benchmarking and other analytical tools considered necessary to establish whether revealed opex is efficient.

CCP sub-panel 14 also stated that in the current environment network business customers are under continual pressure to improve their productivity. CCP sub-panel 14 saw no reason why we should treat networks differently from their customers and considered that we should forecast positive productivity growth when we forecast opex.²⁵⁶ In past decisions, under the base-step-trend approach, we have forecast zero productivity growth when we have determined forecast opex. However, we have noted that distributors should achieve positive productivity growth in the medium to long term.²⁵⁷ More recent information suggests that electricity distributors have improved their opex partial productivity performance in recent years. We will take into account all available information, and the views of all stakeholders, when we forecast opex productivity growth for the 2020–25 period.

²⁵⁴ More information is available at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-operating-environment-factors-for-distribution-network-service-providers>.

²⁵⁵ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, pp. 11–12.

²⁵⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 9.

²⁵⁷ AER, *Jemena distribution determination, 2016 to 2020, Preliminary decision*, Attachment 7, October 2015, pp. 13, 60.

Ergon Energy and Energex submitted that we should provide sufficient detail in the F&A in relation to the application to the tools to their capital and operating expenditure proposals. In particular, we should provide indicative weights that we propose to apply to specific tools. Ergon Energy and Energex also submitted that it is unclear how we will apply benchmarking going forward.²⁵⁸ We disagree with this view and do not consider it necessary to specify the weights that will be applied to specific tools. We apply the guideline to suit the circumstances of each specific reset, including the proposals made and the information available. For example, we may need to place more emphasis on a bottom up assessment if we find a distribution business is relatively inefficient using a top down approach.

²⁵⁸ Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 7.

5 Depreciation

As part of the process of rolling forward a distributor's RAB to the start of the next regulatory control period, we update the RAB for actual capex incurred during the current regulatory control period and also adjust for depreciation. This chapter sets out our proposed approach on the form of depreciation to be used when the Qld distributors' RABs are rolled forward to the commencement of the 2025–30 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.²⁵⁹ In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that the RAB will increase by a lesser amount than if forecast depreciation was used. As a result, the distributor will earn less revenue into the future (i.e. it will bear more of the cost of the overspend into the future) than if forecast depreciation had been used to roll forward the RAB.
- If there is a capex underspend, actual depreciation will be lower than forecast depreciation. This means that the RAB will increase by a greater amount than if forecast depreciation was used. Hence, the distributor will earn greater revenue into the future (i.e. it will retain more of the benefit of an underspend into the future) than if forecast depreciation had been used to roll forward the RAB.

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for the distributor to underspend capex on shorter lived assets compared to longer lived assets as this will lead to a relatively larger increase in the RAB. Use of forecast depreciation, on the other hand, leads to the same incentive for capex regardless of asset lives. This is because using forecast depreciation does not affect the distributor's incentive on capex as the distributor does not lose the full cost of any overspend and is not able to keep all the benefits of any

²⁵⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

5.1 AER's proposed approach

Our proposed approach is to use the forecast depreciation approach to establish the RAB at the commencement of the 2025–30 regulatory control period for the Qld distributors. We consider this approach will provide sufficient incentives for the Qld distributors to achieve capex efficiency gains over the 2020–25 regulatory control period.

5.2 AER's assessment approach

We have to decide for our distribution determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.²⁶⁰

We set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.²⁶¹ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:²⁶²

- 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 incentives guideline
- the capital expenditure factors.

5.3 Reasons for AER's proposed approach

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB for the Qld distributors at the commencement of the 2025–30 regulatory control period.

We had regard to the relevant factors in the NER in developing the approach for deciding on the form of depreciation set out in our capex incentives guideline.²⁶³

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

²⁶⁰ NER, cl. S6.2.2B.

²⁶¹ NER, cl. 6.4A(b)(3).

²⁶² NER, cl. S6.2.2B.

²⁶³ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

- a distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher powered incentive.

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

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

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

The opening RAB at the commencement of the 2020–25 regulatory control period will be established using forecast depreciation, as stated in our previous determination that applies to the Qld distributors for the 2015–20 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2025–30 regulatory control period therefore maintains the current approach. The Qld distributors are currently subject to a CESS and we propose to continue to apply the CESS in the 2020–25 regulatory control period. We discuss this in section 3.3.

For the Qld distributors, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.²⁶⁴ Our ex post capex measures are set out in the capex incentives guideline. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

We received two submissions in relation to our proposed approach on the form of depreciation to be used. CCP sub-panel 14, Ergon Energy and Energex agreed that the use of forecast depreciation in conjunction with the CESS provides sufficient incentives to pursue capex efficiency gains over the 2020-25 regulatory period.²⁶⁵ CCP sub-panel 14 further submitted that the approach would benefit consumers through lower regulated prices.²⁶⁶

QCOS raised a number of issues in regard to assets that have been destroyed or otherwise no longer functioning.²⁶⁷ Typically, the value of assets that are replaced, before

²⁶⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19, 20–21.

²⁶⁵ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, pp. 3, 13; Energy Queensland, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 3 May 2018, p. 7.

²⁶⁶ Consumer Challenge Panel (sub-panel 14), *Submission on AER's preliminary framework and approach for Qld DNSPs*, 4 May 2018, p. 13.

²⁶⁷ Queensland Council of Social Service, *Submission on AER's preliminary framework and approach for Qld DNSPs*, 2 May

their normal life, remain in the asset base. This allows the DNSP to recover the investment. The replacement of the assets may occur through additional capital expenditure, or at no cost if insured. Pass-through arrangements would only apply if the losses resulted from an eligible pass-through event and if the costs are material.

The AER's approach to estimating corporate income tax is being reviewed and may result in changes to the roll-forward model and post-tax revenue model.²⁶⁸

2018, p. 7.

²⁶⁸ See <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-rate-of-return-guideline> and <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-regulatory-tax-approach-2018>.

Appendix A: List of submissions

AGL Energy Limited

Consumer Challenge Panel (Sub-Panel 14)

Electrical Trades Union

Energy Queensland Limited

Queensland Council of Social Service Inc.

Appendix B: Rule requirements for classification

We must have regard to four factors when classifying distribution services.²⁶⁹

1. the form of regulation factors in section 2F of the NEL:
 - the presence and extent of any barriers to entry in a market for electricity network services
 - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider
 - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market
 - the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user
 - the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service
 - the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be)
 - the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.²⁷⁰
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)²⁷¹
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)²⁷²
4. any other relevant factor.²⁷³

²⁶⁹ NER, cl. 6.2.1(c).

²⁷⁰ NEL, s. 2F.

²⁷¹ NER, cl. 6.2.1(c)(2).

²⁷² NER, cl. 6.2.1(c)(3).

²⁷³ NER, cl. 6.2.1(c)(4).

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.²⁷⁴

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.²⁷⁵

In classifying direct control services that have previously been subject to regulation under the present or earlier legislation, we must also follow the requirements of clause 6.2.2(d) of the NER.

²⁷⁴ NER, cl. 6.2.2(c).

²⁷⁵ NER, cl. 6.2.2(c).

Appendix C: Proposed service classification of Qld distribution services 2020–25²⁷⁶

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
Common distribution service—use of the distribution network for the conveyance/flow of electricity (including the services relating to network integrity)			
Common distribution service (formerly 'network services')	<p>The suite of activities that includes, but is not limited to, the following:</p> <ul style="list-style-type: none"> the planning, design, repair, maintenance, construction, and operation of the distribution network the relocation of assets that form part of the distribution network but not relocations requested by a third party (including a customer) works to fix damage to the network (including emergency recoverable works caused by a customer or third party) support for another distributor during an emergency event procurement and provision of network demand management activities for distribution training internal staff and contractors undertaking direct 	Standard control	Standard control

²⁷⁶ The examples and activities listed in the 'Further description' column are not intended to be an exhaustive list and some distributors may not offer all activities listed. Rather the examples provide a sufficient indication of the types of activities captured by the service.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>control services</p> <ul style="list-style-type: none"> • activities related to ‘shared asset facilitation’ of distributor assets • emergency disconnect for safety reasons and work conducted to restore a failed component of the distribution system to an operational state upon investigating a customer outage • rectification of simple customer fault (e.g. fuse) relating to a life support customer or other critical health and safety issues • establishment and maintenance of national metering identifiers (NMIs) in market and/or network billing systems, and other market and regulatory obligations • ongoing inspection of private electrical works (not part of the shared network) required under legislation for safety reasons <p>Such services do not include a service that has been separately classified, including any activity relating to that service.</p>		

Connection services—services relating to the electrical or physical connection of a customer to the network

Premises connections	<p>Includes any additions or upgrades to connection assets located on the customer’s premises for:</p> <p>A. major customer connections²⁷⁷</p>	<p>A. Alternative control B. Standard control</p>	<p>A. Alternative control B. Standard control</p>
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²⁷⁷ Generally, major customers are those customers who connect under the Individually Calculated Customer and Connection Asset Customer tariff classes as per the distributor’s pricing proposal, including real estate developments as set out in the distributor’s connection policy.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>B. small customer connections.²⁷⁸</p> <p>Note: This service includes design, construction, commissioning and energisation of connection assets (including administration services (e.g. reconciling project financials) and generation required to supply existing customers while equipment is de-energised to allow testing and commissioning to occur). It excludes all metering services and services separately identified under 'Connection management services'.</p>		
Extensions	<p>An enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a network service provider to facilitate:</p> <p>A. a new or altered major customer connection,²⁷⁹ where the network extension will be dedicated to the exclusive use of the major customer at the time of installation and energisation and there is no reasonable likelihood</p>	<p>A. Alternative control</p> <p>B. Alternative control</p> <p>C. Standard control</p>	<p>A. Alternative control</p> <p>B. Standard control</p> <p>C. Standard control</p>

²⁷⁸ Generally, small customers are those customers who connect under the Standard Asset Customer tariff classes as per the distributor's pricing proposal, excluding real estate developments as set out in the distributor's connection policy.

²⁷⁹ Generally, major customers are those customers who connect under the Individually Calculated Customer and Connection Asset Customer tariff classes as per the distributor's pricing proposal, including real estate developments as set out in the distributor's connection policy.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>that the network extension will be used to supply another customer or customers within the time period set out in the distributor’s Connection Policy</p> <p>B. a new or altered major customer connection,²⁸⁰ where the distributor considers there is a reasonable likelihood that the network extension will be used to supply another customer or customers within the time period set out in the distributor’s Connection Policy (i.e. will form part of the shared network)</p> <p>C. a new or altered small customer connection.²⁸¹</p>		
Augmentations	<p>Any shared network enlargement/enhancement undertaken by a distributor, which is not an extension, to facilitate:</p> <p>A. a new or altered major customer connection²⁸²</p> <p>B. a new or altered small customer connection²⁸³</p>	<p>A. Alternative control</p> <p>B. Standard control</p> <p>C. Alternative control</p>	<p>A. Standard control</p> <p>B. Standard control</p> <p>C. Alternative control</p>

²⁸⁰ Generally, major customers are those customers who connect under the Individually Calculated Customer and Connection Asset Customer tariff classes as per the distributor’s pricing proposal, including real estate developments as set out in the distributor’s connection policy.

²⁸¹ Generally, small customers are those customers who connect under the Standard Asset Customer tariff classes as per the distributor’s pricing proposal, excluding real estate developments as set out in the distributor’s connection policy.

²⁸² Generally, major customers are those customers who connect under the Individually Calculated Customer and Connection Asset Customer tariff classes as per the distributor’s pricing proposal, including real estate developments as set out in the distributor’s connection policy.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	C. the removal of a network constraint faced by an embedded generator.		
Connection management services	<p>Works initiated by a customer or retailer which are specific to the connection point. Includes, but is not limited to:</p> <ul style="list-style-type: none"> • connection application services • de-energisation²⁸⁴ • re-energisation • temporary connections • remove or reposition connection • 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 • protection and power quality assessment • customer requested change requiring 	Alternative control	Alternative control

²⁸³ Generally, small customers are those customers who connect under the Standard Asset Customer tariff classes as per the distributor’s pricing proposal, excluding real estate developments as set out in the distributor’s connection policy.

²⁸⁴ De-energisation services related to business as usual activities and de-energisation services that may relate to changing over meter types

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>secondary and primary plant studies for safe operation of the network (e.g. change protection settings)</p> <ul style="list-style-type: none"> • rectification of illegal connections or damage to overhead or underground service cables • calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER • assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers • processing preliminary enquiries requiring site specific or written responses • undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants • site inspection in order to determine the nature of the connection service sought by the 		

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>connection applicant and ongoing co-ordination for large projects</p> <ul style="list-style-type: none"> registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER. 		
Enhanced connection services	<p>Activities include:</p> <ul style="list-style-type: none"> provision of connection services above minimum requirements – customer requests increase in reliability or quality of supply beyond the standard, and/or above minimum regulatory requirements (e.g. reserve feeder) supply enhancement (e.g. upgrade from single phase to three phase) upgrade from overhead to underground service 	Alternative control	Alternative control

Metering services²⁸⁵

²⁸⁵ The Qld distributors will continue to be responsible for existing type 5 and 6 meters until they are replaced (and entitled to levy associated charges). We refer to these meters as 'legacy meters'. New meters (that will be type 1 to 4 meters) installed from 1 December 2017 are referred to as 'contestable meters'. The Qld distributors will continue to be solely responsible for the Mount Isa-Cloncurry supply network, which is not connected to the NEM.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
Type 1 to 4 metering services	Type 1 to 4 metering installations ²⁸⁶ and supporting services are competitively available.	Unregulated	Unregulated
Type 5 and 6 meter installation and provision (prior to 1 December 2017)	Recovery of the capital cost of type 5 and 6 metering equipment (including meters with internally integrated load control devices).	Alternative control	Alternative control
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Standard control	Standard control
Types 5 and 6 meter maintenance, reading and data services (legacy meters)	<p>Meter maintenance covers works to inspect, test, maintain and repair metering installations.</p> <p>Meter reading refers to quarterly or other regular reading of a metering installation.</p> <p>Metering data services are those that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of</p>	Alternative control	Alternative control

²⁸⁶ Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	relevant NMI Standing Data in accordance with the NER.		
Auxiliary metering services (Type 5 to 7 metering installations)	<p>Activities include:</p> <ul style="list-style-type: none"> • Off-cycle meter reads for type 5 and 6 meters. • Requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation. • Testing and maintenance of instrument transformers for type 5 and 6 metering purposes. • Type 5 to 7 non-standard metering services. • Works to re-seal a type 5 or 6 meter due to customer or third party action (e.g. by having electrical work done on site). • Change distributor load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement. 	Alternative control	Alternative control
Type 5 and 6 meter installation and provision (Mount Isa-Cloncurry supply network only)	On site installation or upgrade (at a customer's request) by Ergon Energy of a type 5 or 6 metering installation at a customer's premises in the Mount Isa-Cloncurry supply network.	Alternative control	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>Load control services provided by a type 5 or 6 metering installation are grouped with metering services and classified as alternative control.</p> <p>Ergon Energy may recover the capital cost of types 5 and 6 metering equipment (including meters with internally integrated load control devices) replaced on or after 1 December 2017, where the replacement was initiated by Ergon Energy.</p>		
Types 5 and 6 meter maintenance, reading and data services (Mount Isa-Cloncurry Network)	<p>Meter maintenance covers works to inspect, test, maintain and repair metering installations. It also includes the removal and disposal of a metering installation at customers' premises.</p> <p>Meter reading refers to quarterly or other regular reading of a metering installation.</p> <p>Metering data services are those that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of relevant NMI Standing Data in accordance with the NER.</p>	Alternative control	Alternative control
Additional auxiliary metering services (Mount Isa-Cloncurry supply network only)	Metering services offered by Ergon Energy in the Mount Isa-Cloncurry supply network for type 5	Alternative control	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>and 6 metering installations:</p> <p>Provision and installation of instrument transformers for type 5 and 6 metering purposes.</p> <p>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.</p>		
Emergency maintenance of failed metering equipment not owned by the distributor (contestable meters)	The distributor is called out by the customer or their agent (e.g. retailer, metering coordinator or metering provider) due to a power outage where an external metering provider's metering equipment has failed or an outage has been caused by the metering provider and the distributor has had to restore power to the customer's premises. This may result in an unmetered supply arrangement at this site. This fee will also be levied where a metering provider has requested the distributor to check a potentially faulty network connection and when tested by the distributor, no fault is found.	Alternative control	Alternative control
Meter recovery and disposal – type 5 and 6 (legacy meters)	<p>Activities include the removal and disposal of a type 5 or 6 metering installation:</p> <ul style="list-style-type: none"> At the request of the customer or their agent, 	Alternative control	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>where an existing type 5 or 6 metering installation remains installed at the premises and a replacement meter is not required.</p> <ul style="list-style-type: none"> At the request of the customer or their agent, where a permanent disconnection has been requested where it has not been removed and disposed of by the incoming metering provider. 		
Third party requested outage for purposes of replacing meter	At the request of a retailer or metering coordinator, provides notification to affected customers, and isolates power at a customer's premises to facilitate the replacement of the existing metering installation by an external metering provider.	Alternative control	Alternative control
Network metering services	Bulk supply point meeting	Standard Control	Standard Control
Network ancillary services – Services closely related to common distribution services but for which a separate charge applies			
Access permits, oversight and facilitation	<p>Activities include:</p> <ul style="list-style-type: none"> A distributor issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage. A distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space. 	Alternative control	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<ul style="list-style-type: none"> • A distributor providing access to switch rooms, substations and the like to a non-Local Network Service Provider party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas. • Specialist services (which may involve design related activities and oversight/inspections of works) where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets. • Facilitation of generator connection and operation of the network. • Facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets. 		
Notices of arrangement and completion notices	<p>A distributor may be required to perform work of an administrative nature where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This may include receiving and checking subdivision plans, copying subdivision plans, checking and recording easement details, assessing supply availability, liaising with developers if errors or changes are required and preparing notifications of arrangement.</p> <p>A distributor may also be required to provide a completion notice (other than a notice of arrangement). This applies where the real estate developer requests the distributor to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to meet contractual undertakings.</p>	Alternative control	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
Network related property services	<p>Activities include:</p> <ul style="list-style-type: none"> Property tenure services related to providing advice on, or obtaining: deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with a connection or relocation. Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer. 	Unregulated	Alternative control
Network safety services	<p>Examples include:</p> <ul style="list-style-type: none"> provision of traffic control and safety observer services by the distributor where required fitting of tiger tails and aerial markers high load escorts customer initiated outage (e.g. to allow customer and/or contractor to perform maintenance on the customer’s assets, work close or for safe approach) 	Alternative control	Alternative control
Sale of approved materials or equipment	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network.	Alternative control	Alternative control
Planned Interruption – Customer requested	<p>Examples include:</p> <ul style="list-style-type: none"> Where the customer requests to move a distributor planned interruption and agrees to fund the additional cost of performing this distribution 	Alternative control	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<p>service outside of normal business hours.</p> <ul style="list-style-type: none"> customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach, which impacts other networks users). 		
Attendance at customers' premises to perform a statutory right where access is prevented.	<p>A follow up attendance at a customer's premises to perform a statutory right where access was prevented or declined by the customer on the initial visit. This includes the costs of arranging, and the provision of, a security escort or police escort (where the cost is passed through to the distributor).</p>	Alternative control	Alternative control
Inspection and auditing services	<p>Activities include:</p> <ul style="list-style-type: none"> inspection and reinspection by a distributor, of gifted assets or assets that have been installed or relocated by a third party investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider due to unsafe practices or substandard workmanship auditing of a third party service provider's work practices in the field after hours²⁸⁷ examination and/or testing of the consumer mains and main switchboard prior to initial energisation (upon request) after hours visual examination of an electrical installation to reconnect it to a source of electricity (upon request) 	Alternative control	Alternative control

²⁸⁷ We note that this "after hours" reference is included because it specifically relates to sections 219 and 220 of the *Electrical Safety Regulation 2013 (Qld)*.

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
	<ul style="list-style-type: none"> re-test at a customer’s installation, where the installation fails the initial test and cannot be connected. 		
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor’s network. Such learning outcomes may include those necessary to demonstrate competency in the distributor’s electrical safety rules, to hold an access authority on the distributor’s network and to carry out switching on the distributor’s network. Examples of training might include high voltage training, protection training or working near power lines training.	Unregulated	Alternative control
Authorisation and approval of third party service providers design, work and materials	<p>Activities include:</p> <ul style="list-style-type: none"> Authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party service providers (excludes training services). Acceptance of third party designs and works. Assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor’s approved materials list. 	Alternative control	Alternative control
Security lights	<p>Provision, installation, operation and maintenance of equipment mounted on a distribution pole used for security services, e.g. nightwatchman lights</p> <p>Note: excludes connection services.</p>	Unregulated	Alternative control

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
Customer initiated network asset relocations/re-arrangements	Relocation of assets that form part of the distribution network in circumstances where the relocation was initiated by a third party (including a customer).	Alternative control	Alternative control
Customer requested provision of electricity network data	Requests for the provision of electricity network data requiring customised investigation, analysis or technical input (e.g. requests for zone substation data), where there is no demonstrable net benefit to the distribution network.	Alternative control	Alternative control
Fault response (Not DNSP fault)	Attendance at a customer’s premises to restore supply or investigate power quality issues where it is determined that the fault was not related to the distributor’s equipment or infrastructure (this excludes circumstances where the fault relates to the network).	Alternative control	Alternative control
Third party funded network alterations or other improvements	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to be installed on the shared distribution network. This does not relate to upstream distribution network augmentation.	Alternative control	Alternative control
Public lighting			
Public lighting	Includes the provision, construction and maintenance of public lighting and emerging public lighting technology.	Alternative control	Alternative control
Unregulated distribution services – (non-exhaustive list)			
Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc.).	Unregulated	Unregulated

Service group	Further description	Current classification 2015–20	AER proposed – classification 2020–25
Contestable metering support roles	Includes metering coordinator, metering data provider and metering provider for Type 1 to 4 metering installations.	Unregulated	Unregulated
Provision of training to third parties for non-network related access	Training programs provided to third parties, not related to network access.	Unregulated	Unregulated
Type 5 and 6 meter data management to other electricity distributors	The provision of type 5 and 6 meter data management to other electricity distributors.	Alternative control	Unregulated
Distribution services provided in unregulated isolated networks	Ownership and operation of isolated supply networks, other than the Mount Isa-Cloncurry supply network (Ergon Energy).	Unregulated	Unregulated
Hayman Island undersea cable		Unregulated	Unregulated
Inspection of private network infrastructure	Private inspection of privately owned low voltage or high voltage network infrastructure (i.e. privately owned distribution infrastructure before the meter).	Unregulated	Unregulated