



PRELIMINARY DECISION
Energex determination 2015–16
to 2019–20

Attachment 16 – Alternative
control services

April 2015

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Note

This attachment forms part of the AER's preliminary decision on Energex's 2015–20 distribution determination. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators

Shortened form	Extended form
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

16 Alternative control services

Alternative control services are those that are provided by distributors to specific customers. They do not form part of the distribution use of system revenue allowance provide by us to each distributor. Rather, distributors recover the costs of providing alternative control services through a selection of fees, most of which are charged on a 'user pays' basis.

This section describes the AER's determination on the charges that distributors can levy customers for the provision of ancillary network services, public lighting and metering.

16.1 Ancillary network services

For the purposes of this preliminary decision, we have referred to the service groups previously identified as 'fee based services' and 'quoted services' collectively as a single group called 'ancillary network services'.

The existing 'fee based services' and 'quoted services' groupings describe the basis on which service prices are determined. Ancillary network services share the common characteristic of being non-routine services provided to individual customers on an as requested basis.¹

We classify ancillary network services as direct control services. Having decided to apply a direct control classification, we must further classify ancillary network services as either standard control or alternative control. We have classified them as alternative control services because they are attributable to individual customers.²

16.1.1 Preliminary Decision

We do not approve a number of Energex's proposed fees for ancillary network services. For these services, Energex's proposed fees are higher than fees based on maximum labour rates (for the distributor's labour types) which we consider efficient for providing these services. More detail on our reasoning is in section 16.1.4.

Appendix A.1 contains our preliminary decision on the fees Energex can charge for ancillary network services for the first year of the 2015–20 regulatory control period.

Table 16.23 sets out charges for fee based and quoted services.

¹ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 45.

² AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 46.

Form of control

Our preliminary decision is to apply a price cap for the form of control to ancillary network services. Figure 16.1 and Figure 16.2 set out the control mechanism formulas for fee based services and quoted services, respectively. They are consistent with the formulas which Ergon Energy agreed on in its regulatory proposal.³

Form of control—fee based services

Our preliminary decision is to apply a price cap for the form of control to fee based services.⁴ This is consistent with the form of control applied in the 2010–15 regulatory period. Under this form of control, a schedule of prices is set for the first year. For each of the following years, the previous year’s prices are adjusted by CPI and an X factor. The formula to give effect to the price cap is set out below:

Figure 16.1 Fee based ancillary network services formula

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1

p_i^t is the cap on the price of service i in year t. However, for 2015–16 this is the price as determined in Table 16.23.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015–16 year, t–2 is December 2013 and t–1 is December 2014 and in the 2016–17 year, t–2 is December 2014 and t–1 is December 2015 and so on.

X_i^t is the X-factor for service i in year t as Table 16.1 sets out.

Table 16.1 AER preliminary decision on X factors for each year of the 2015–20 period (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–0.74	–0.72	–0.74	–0.77

Source: AER analysis.

Note: To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as defacto X factors. Therefore, they are negative.

³ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 65; Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, pp. 74-75.

⁴ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 67.

A_i^t is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life. For ancillary network services we consider the value for A is zero.

Form of control— quoted services

The AER's preliminary decision is to apply a formula to determine the cost build-up of services that are priced on a 'quoted' basis.⁵

Figure 16.2 Quoted services formula

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Materials} + \text{Capital Allowance}$$

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 $(1-X_i)(1+\Delta\text{CPI})$.⁶

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. Contractor services are escalated annually by ΔCPI .

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads. Materials are escalated annually by ΔCPI .

Capital Allowance represents a return on and return of capital for non-system assets.

16.1.2 Energex's proposal

Energex accepted our proposed classification of ancillary network services as alternative control services and developed price caps and quoted prices in accordance with our F&A paper.⁷

Energex proposed that the basis of the control mechanism for fee based services is a cost build-up method to establish an efficient price for the first year. Prices for the subsequent years will follow a price path determined by the control mechanism formula. The cost build-up formula, as shown above, is:

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Materials} + \text{Capital Allowance}$$

⁵ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, pp. 67–68.

⁶ The definition of X and ΔCPI in Figure 16.2 are the same as for Figure 16.1.

⁷ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 292.

This formula provides for the recovery of labour, contractor and materials costs, noting that labour is the primary cost driver. It also provides for the recovery of a share of rate of return on non-system assets.

Energex proposed to employ this formula to develop first-year prices for both fee-based and quoted services. The price cap for fee based services will be determined by applying service assumptions which reflect efficient business costs and practices. The price for quoted services will reflect the approved labour and material cost escalators, and the contemporary rate of return at the time the work is requested.⁸

16.1.3 Assessment approach

We focused on the key inputs in determining prices for ancillary network services. We considered:

- Energex's regulatory proposal.⁹
- Maximum total labour rates we developed for Queensland. We based our findings on our consultant, Marsden Jacob's, analysis for our NSW draft decision.¹⁰
- We consider labour is the key input in determining an efficient level of fees for ancillary network services. We focused on comparing Energex's proposed total labour rates against maximum total labour rates that we developed. In this preliminary decision 'total labour rates' comprise raw labour rates, on-costs and overheads.

Our preliminary decision maximum total labour rates apply the following labour components to arrive at a maximum total labour rate (for particular labour types).

- a maximum raw labour rate
- a maximum on-cost rate
- a maximum overhead rate.

As we explain in more detail in section 16.1.4, we obtained maximum rates for each of these components. We applied these maximum (component) rates to derive maximum total labour rates. We consider that using our maximum labour rates to determine appropriate fees for services will provide Energex with a reasonable opportunity to recover at least the efficient costs it incurs in providing these services. It will promote

⁸ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, pp. 258 -261.

⁹ Energex, *Regulatory proposal 2015–20*, 31 October 2014, pp. 256–264, 278–281, 292–294; Energex, *Regulatory proposal 2015–20: Appendix 54—Alternative control services—price cap services*, 31 October 2014, pp. 1–58; Energex, *Regulatory proposal 2015–20: Appendix 55—Alternative control services provided on a quoted basis*, 31 October 2014, pp. 1–5.

¹⁰ Marsden Jacob Associates, *Final provision of advice in relation to alternative control services—public version*, 20 October 2014.

the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services.¹¹

Where Energex's proposed total labour rates exceeded our maximum total labour rates—which we consider represents a prudent approach—we applied our maximum total labour rates to determine ancillary network service charges. Equally, we applied Energex's proposed total labour rates where they sat below our maximum total labour rates.

As a further check of our analysis, we also compared components of Energex's proposed labour costs with those of the Victorian distributors. The latter's costs have generally been considered closer to efficient levels than their interstate counterparts.¹²

16.1.4 Reasons for preliminary decision

We do not approve Energex's proposed fees for ancillary network services. Proposed fees exceed those based on maximum total labour rates (which we consider efficient) for Energex's labour types for providing these services. As we set out in section 16.1.3, we compared Energex's total labour rates against maximum (rather than, for example, average) total labour rates. We note ancillary network services comprise a relatively small portion of Energex's revenue. This is because a relatively small number of Energex's customers request ancillary network services in any given regulatory year. Hence we consider it prudent to use maximum total labour rates as an input to derive prices for ancillary network services. Maximum total labour rates act as 'ceilings' on the rates we consider Energex should pay for the various labour types. Where Energex reveals rates lower than the maximum total labour rates, we consider those lower rates should be the inputs for deriving ancillary network services prices. We consider this ensures the distribution business has a reasonable opportunity to recover at least its efficient costs, while also allowing a return commensurate with the regulatory and commercial risks in providing the services.

AGL submitted that we should carefully review and analyse all proposed ancillary network services fees. Of particular concern to them is the removal of Schedule 8 to the Electricity Regulations 2006 which allowed the State Government to cap prices for certain services.¹³

We carefully assessed Energex's proposed fees for Ancillary Services to ensure they are prudent. Our assessment focused on the inputs to the methods Energex used to derive its fees for ancillary network services. In particular, labour is the major input to Energex's proposed ancillary network service charges. Where there are inefficiencies in actual costs, however, these will be carried through in the derivation of proposed fees. We found proposed labour rates were inefficient. Hence, we adjusted Energex's

¹¹ NEL, s7A and 16.

¹² Deloitte Access Economics, *NSW distribution network service providers labour analysis—Addendum to 2014 report*, April 2015.

¹³ AGL, *AGL Submission to the Australian Energy Regulator*, 30 January 2015, p. 26.

total labour rates where they exceeded the maximum total labour rates that we developed (see section 16.1.4). Specifically, we adjusted the labour rate Energex used for administrative employees. We did this because it was higher than the maximum labour rate which we consider efficient (for this labour type). This translated into price changes for those services which require administrative staff. The downward adjustment of the administrative labour rate reduces the allocated labour cost for such services and therefore decreases the fees that Energex can charge.

The Queensland distributors used different names and descriptions for different labour categories. However, we found that the types of labour used to deliver ancillary network services broadly fell into one of five categories:

- Administration
- Technical services
- Engineers
- Field workers, and
- Senior engineers.¹⁴

Table 16.2 shows the maximum total labour rates we developed for each of Energex's labour types. We consider these maximum total labour rates should be used to assess Energex's proposed charges for ancillary network services.

We assessed raw labour rates (see 16.1.4.1), on-costs (see 0) and overheads (see 0) separately and derived maximum rates for each component. We then applied these maximum rates to produce the maximum total labour rates. It was this maximum rate that was important in our deliberations. The components that make up that maximum were of significantly less relevance.

We used these maximum total labour rates to determine whether Energex's proposed fees for ancillary network services reflect the underlying cost of an efficient labour rate. We consider this to be a prudent approach. It provides the distribution business with a reasonable opportunity to recover at least its efficient costs. We consider fees based on labour rates higher than the maximum total labour rates would be inefficient. The exact make up of those individual rates (raw labour rates, on-cost and overheads) did not form the basis of our reasoning.

¹⁴ Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 1.

Table 16.2: Maximum allowed total labour rates

Labour Category	AER maximum total labour rates (\$ per hour, \$2014–15)
Apprentices	N/A
Power Workers	125.07
Administration/ Clerical	73.90
Customer Connections Labour Rate	N/A
Electrical System Design Advisors	170.55
Technical/ Service Persons	181.92
Para professional	181.92
Supervisors	181.92
Professional Managerial	170.55
System Operators	N/A
Senior Professional	N/A

Source: AER analysis.

Note: Energex claimed confidentiality on its total labour rates.

16.1.4.1 Raw labour rates

In developing maximum raw labour rates (that is, excluding on-costs and overheads), we examined Hays 2014 salary data. The Hays 2014 salary reports draw on information from 2,500 companies across Australia and New Zealand. Relevant distributors in the Hays data who gave permission to be named were ActewAGL, Jemena, and CitiPower.¹⁵ The Hays rates draw from a wide pool of labour which the Queensland distributors would likely have access to. We therefore consider these rates provide a good representation of the competitive market rate for appropriate categories of labour.

We reviewed salary information from all Australian cities. However, we only used Brisbane salary data to develop our maximum raw labour rates.¹⁶ We compared the

¹⁵ A list of contributors to the Hays 2014 salary data who gave permission to be named is available on Hays, *Contributors—Hays 2014 Salary, accessed 12 February 2015, Guide* http://www.hays.com.au/salary-guide/HAYS_375078.

¹⁶ Marsden Jacob Associates, *MJA analysis*.

maximums we developed using the Hays Brisbane data against the Hays Melbourne data. We did this as a cross-check to test the reasonableness of our maximum raw labour rates. We found that our maximum raw labour rates did not differ significantly from the Hays Melbourne data.

For illustrative purposes, we also looked at raw labour rates (across the five benchmark labour categories) for Sydney and Auckland. Labour rates in each category did not vary significantly across these locations. The differences observed probably captured differences between locations (including economic conditions, labour laws, and population). For these reasons, we consider that the Brisbane rates alone were acceptable to develop maximum labour rates for ancillary network service charges for the Queensland distributors.

To calculate the maximum raw labour rates, we used job titles from Hays' energy specific salary guide.¹⁷ We supplemented this with data from the Hays office support salary guide.¹⁸ This ensured that the 'administration' category was sufficiently covered.

We analysed 66 different job titles and used 36 of these to develop maximum raw labour rates for the five labour categories.

Table 16.3 shows the job titles we used to develop maximum labour rates for each of the five labour categories. These 36 labour job titles involved tasks which clearly fell into either the 'administration', 'technical specialist', 'engineer', 'field worker', or 'senior engineer' labour categories. We excluded job titles that were not relevant to electricity distributors such as 'wind farm engineer'. Table 16.3 shows the 36 job titles we used to develop recommended maximum labour rates for each of the five labour categories. We consider these 36 job titles provide Marsden Jacob with a sample of labour rates available in a competitive labour market.

Table 16.3: Job titles we used to develop maximum labour rates

Labour category	Job title
Admin	Project secretary / Administrator
	Client liaison (residential)
	Data entry operator
	Records officer
	Administration assistant (12+ months experience)
	Project administration assistant (3+ years experience)
Technical specialist	Project coordinator
	Technician

¹⁷ Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

¹⁸ Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

Labour category	Job title
	Control room operator
	Control room manager
	E&I technician
	Protection technician
	Generator technician
	Operator / manager
	Site engineer
	Planner / scheduler
	OHS supervisor
	OHS manager
Engineer	Design engineer
	Project engineer (EPCM)
	Power systems engineer
	Protection engineer
	Transmission line design engineer
	Asset engineer (3 to 7 years)
	Project engineer
Field worker	Leading hand
	Electrician
	Mechanical fitter
	Line worker
	G&B linesworker
	Cable joiner
	Cable layer
Senior engineer	Senior design engineer
	Principal design engineer
	Senior project engineer (EPCM)
	Commissioning Engineer

Source: Marsden Jacob analysis

We considered the range of data provided for each labour category across the various job titles. In doing this, we derived salary ranges for each labour category by:

- identifying the lowest salary from all job titles in the labour category

- identifying the highest salary from all job titles in the labour category.

We consider this range represents the full pool of labour (and raw labour rates) that Energex would have access to in a competitive market. We consider that the maximum raw labour rate for each labour category should be used to develop its maximum total labour rate. We consider this to be a prudent approach. It provides the distribution business with a reasonable opportunity to recover at least its efficient costs, while promoting the efficient provision of services.

Table 16.4: AER maximum raw labour rates

Labour Category	AER maximum raw labour rates (\$ per hour, \$2014–15)
Apprentices	N/A
Power Workers	52.88
Administration/ Clerical	31.25
Customer Connections Labour Rate	N/A
Electrical System Design Advisors	72.12
Technical/ Service Persons	76.92
Para professional	76.92
Supervisors	76.92
Professional Managerial	72.12
System Operators	N/A
Senior Professional	N/A

Source: AER analysis.

16.1.4.2 On-costs

We consider that a maximum on-cost rate of 43.5 per cent should apply to the Queensland distributors. We calculated this maximum on cost rate by developing a 'bottom up' estimate of on costs for the Queensland distributors, with reference to the following factors:

- the superannuation levels included in each distributor's enterprise bargaining agreement
- a conservative estimate of workers compensation premium
- standard payroll tax rates in Qld

- annual leave loading of 17.5 per cent loading on four weeks annual leave, which equates to 1.35 per cent of total salary.
- a conservative long service leave allowance based on three months leave for every ten years of service, equating to 2.5 per cent per year.
- an assumed rate of 18.18 per cent standard leave (including annual leave, sick leave, and public holidays) for all businesses.
- We developed our numbers for each of these factors based on Energex's Enterprise Agreement and the Queensland State Payroll Tax.¹⁹ We used this maximum on-cost rate of 43.5 per cent in deriving our maximum total labour rates. It provides the distribution business with a reasonable opportunity to recover at least its efficient costs.

Table 16.5 shows our maximum on-cost rate and the breakdown of that on-cost rate.

Table 16.5: On-cost rate breakdown and maximum, per cent

On-Cost Rate Component	Maximum Rates	Energex's Labour On-Cost Rate for the regulatory period
Standard Leave	18.18	
Superannuation	9.00	
Workers Compensation	2.25	
Payroll Tax	4.75	
Annual Leave Loading	1.35	
Long Service Leave Allowance	2.5	
Total on-cost rate	43.33	Confidential

Source: AER analysis.

16.1.4.3 Overheads

We determined the maximum overhead rate based on Marsden Jacob's report which assessed alternative control services for NSW and ACT distributors. Marsden Jacob recommended a 65 per cent overhead rate maximum in its report.²⁰ In recommending

¹⁹ Energex, *Energex Union Collective Agreement*, pp. 47-57.

²⁰ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

this maximum overhead rate, Marsden Jacob compared the overhead rates the ACT and NSW distributors proposed (in their initial regulatory proposals). Marsden Jacob found that Ausgrid and Endeavour Energy's overhead rates were significantly higher than those of Essential Energy and ActewAGL, as well as the Victorian businesses' overhead rates.²¹ Marsden Jacob therefore recommended an overhead rate maximum of 65 per cent, based on the maximum of only ActewAGL and Essential Energy's proposed overhead rates. Marsden Jacob's maximum overhead rates are also higher than the rates proposed by the Queensland distributors.²² This adds further support to using Marsden Jacobs' maximum overhead rates to calculate maximum total labour rates. We consider that:

- an overhead rate maximum of 65 per cent should apply to all Qld distributors and
- maximum total labour rates (which use an overhead rate of 65 per cent), are prudent.
- It provides the distribution business with a reasonable opportunity to recover at least its efficient costs.

In its discussion of maximum overhead rates, Marsden Jacob noted:

- the nature of the differences in overhead rates may be due to cost allocation issues
- capping the overhead rate may have unintended consequences for the broader cost allocation methodology.
- we should test the method of addressing overhead allocation vis a vis the cost allocation method.²³

We reviewed the objectives of our cost allocation guideline. The cost allocation method sets out the principles and policies for attributing costs to, or allocating costs between, the categories of distribution services a distributor provides. Hence, in approving a distributor's cost allocation method, we approve the methodology it uses to allocate costs. This does not equate to approving the costs. The approval of actual costs is subject to applicable requirements set out in the National Electricity Rules and the National Electricity Law.²⁴ Proper application of the cost allocation method does not indicate whether the distributor's expenditure, including overheads, is at efficient levels or otherwise reflects the requirements of the NER, having regard to the revenue and pricing principles and the national electricity objective.²⁵ By extension, proper

²¹ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

²² Ergon Energy, *Regulatory proposal 2015-20: 05.06.02—fixed fee services model*, 31 October 2014 (CONFIDENTIAL); Ergon Energy, *Regulatory proposal 2015-20: 05.06.03—quoted price services model*, 31 October 2014 (CONFIDENTIAL); Energex, *Regulatory proposal 2015-20: Alternative control services costing model*, 31 October 2014 (CONFIDENTIAL).

²³ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

²⁴ AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

²⁵ AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

application of the cost allocation method does not indicate whether the resulting overhead rates represent efficient levels.

16.2 Metering

Our preliminary decision on Energex's metering proposal is made in the context of ongoing policy reform. We based our assessment on the National Electricity Rules (NER) in place at the time of this preliminary decision, but have had regard to the likelihood of policy reform in the future through rule changes that will apply during this regulatory period.

Currently, competition in metering is limited to large customers in the national electricity market while regulated distributors have the sole responsibility to provide small customers with metering services.²⁶

The Australian Energy Market Commission (AEMC) is undertaking a rule change process to expand competition in metering and related services to help facilitate a market led roll out of advanced metering technology, following proposals from the COAG Energy Council. The increased availability of advanced meters will enable the introduction of more cost reflective network prices and allow consumers to make more informed decisions about how they want to use energy services.

The AEMC published its draft rule on 26 March 2015. It provides that the AER should determine 'the arrangements for a DNSP to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.²⁷ Other key features of the draft rule change include:

- the transfer of the role and responsibilities of the existing 'Responsible Person' to a new type of Registered Participant called a Metering Coordinator
- allowing any person to become a Metering Coordinator, subject to meeting the registration requirements
- permitting a large customer to appoint its own Metering Coordinator
- requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.²⁸

Our preliminary decision takes the AEMC's draft rule into account and establishes a regulatory framework for the 2015–20 regulatory control period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.²⁹ This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

²⁶ NER clause 7.2.3(a). Small customers refers to any customer with less than 160MWh annual consumption (effectively all residential and small business customers fall into this category).

²⁷ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

²⁸ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. iii.

²⁹ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 79.

The key issue in the lead up to competition is how to recover the residual metering capital costs that arises when metering customers begin to switch to competitive metering providers. Rather than an upfront exit fee which would create a regulatory barrier to competitive entry, our preliminary decision is that switching customers continue to pay the capital cost component of the regulated annual metering service charge.

16.2.1 Preliminary decision

Our preliminary decision is to maintain the alternative control services classification for type 5 and 6 metering services set out in our framework and approach.³⁰ We further maintain that the control mechanism for alternative control services will be caps on the prices of individual services.³¹

16.2.1.1 Structure of metering charges

We classify type 5 and 6 metering services as alternative control services. The control mechanism for alternative control metering services will be caps on the prices of individual services.

Our preliminary decision approves two types of metering service charges:

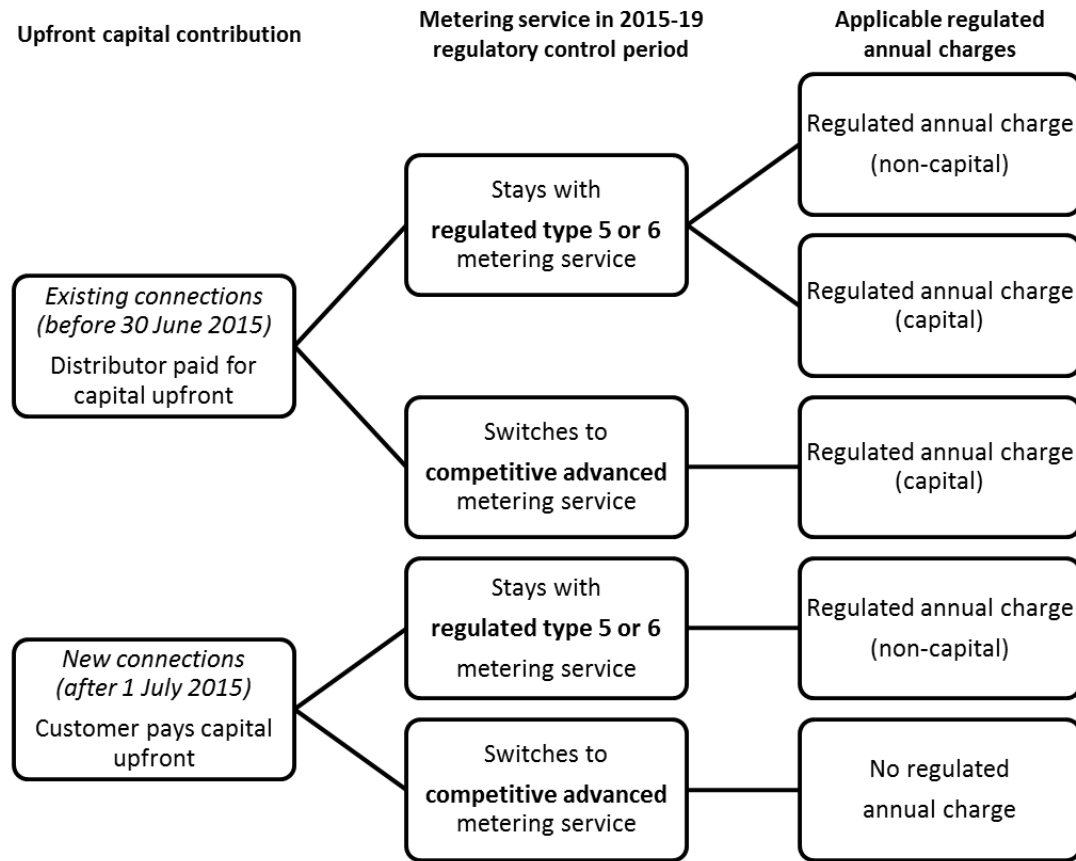
- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising of two components:
 - capital —metering asset base (MAB) recovery
 - non-capital—operating expenditure and tax.

Figure 16.3 depicts how the two regulated annual charge components relate to different metering customers.

³⁰ AER, *Final framework and approach for Energex and Ergon Energy*, April 2014. p. 21

³¹ AER, *Final framework and approach for Energex and Ergon Energy*, April 2014. p. 52

Figure 16.3 – Preliminary decision – applicable regulated annual charges



Source: AER analysis.

Note: This diagram shows regulated annual charges only. In addition, customers who switch may incur charges for their competitive advanced metering service. Any such charges are not subject to AER oversight and are not shown in the diagram above.

Existing connections (before 30 June 2015)

For regulated meters installed before 30 June 2015, metering capital costs were amortised. That is, distributors paid upfront for the capital costs which were then added to the asset base and recovered gradually through annual charges.

If a customer with an existing regulated metering connection on their premises receives a regulated type 5 or 6 metering service, they pay the following charges:

- Capital (MAB recovery³²) component of regulated annual metering charge
- Non-capital (opex and tax) component of the regulated annual metering charge.

³² The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–20 regulatory control period to include forecast replacement capex. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

If a customer with an existing regulated metering connection on their premises chooses to switch to a competitive advanced metering service (and no longer receives a regulated type 5 or 6 metering service) they stop paying the non-capital component of the regulated annual metering charge. They will pay the following charges:

- Capital component of the regulated annual metering charge.

This charge recovers the MAB from all customers with existing connections (from before 30 June 2015) on their premises, whether or not they subsequently switch from their existing regulated meter to an advanced meter. As a result, the diminishing number of customers who remain with their existing regulated meters are not required to pay the entire capital cost of the MAB. This has the benefit of minimising cross subsidies between customers switching to competitive meters and those remaining on regulated meters. It also means the contribution towards the recovery of the metering asset base is relatively small because it is paid through ongoing annual charges rather than an upfront exit fee.

- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.3.

This structure applies even if a customer pays upfront for a meter upgrade to their existing regulated meter after 1 July 2015 (for example, wants to upgrade from a type 6 to a type 5 meter) and then switches to a competitive advanced metering provider. This is because the upfront capital charge recovers the costs of the meter upgrade, but not of the existing meter installed before 30 June 2015.

New connections (after 1 July 2015)

For regulated new meter connections installed after 1 July 2015, the capital costs will be paid upfront by the customer. As such, no capital expenditure related to new meter connections installed after this date will be added to the metering asset base.

If a customer has a new regulated metering connection that was installed on their premises after 1 July 2015 and receives a regulated type 5 or 6 metering service, they pay the following charges:

- Non-capital component of the regulated annual metering charge
- As they have already paid for their capital component upfront, the only costs relating to their regulated metering service left to be recovered through annual charges are the non-capital costs.

If a customer has a new regulated metering connection on their premises and wants to switch to a competitive advanced metering service (and no longer receives a regulated type 5 or 6 metering service), they stop paying all regulated annual metering charges. They will pay the following charges:

- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.3.

16.2.1.2 Annual metering services

We generally accept Energex's building block approach as the basis for establishing annual metering charges. This is a summary of our decisions on the individual components:

- Opening metering asset base
- Our preliminary decision is to approve an opening metering asset base (MAB) value as at 1 July 2015 of \$448.8 million and substitute it with Energex's proposed \$435.9 million (\$nominal).
- Our opening MAB value is higher than proposed because we determined that certain load control assets should be moved across from the regulatory asset base (RAB) for standard control services.
- Depreciation
- We accept Energex's proposed standard asset lives of 15 years. This economic lifetime reflects the expected technical usefulness of Energex's meters.
- Our preliminary decision does not accept the proposed remaining asset lives. We have made adjustments to the remaining asset lives as at 1 July 2010 and actual net capex in relation to the standard control services RAB. This in turn impacts on the weighted average remaining lives of assets in the MAB at 1 July 2015 (see attachment 2 for more information).
- We will apply forecast, not actual, depreciation. This is consistent with our approach for standard control services.
- Forecast capex
- We do not accept Energex's proposed capex building block. Our preliminary decision allows \$29.4 million in capex for annual metering charges instead of Energex's proposed \$160.1 million (\$2014-15). Of the capex we have not accepted, approximately 78 percent relates to our preliminary decision to move the cost recovery of new connections from the annual metering charge to upfront payments. That is, Energex should still recover this expenditure, but via a different capitalisation policy.
- Forecast opex
- In assessing the metering opex building block, we used a base-step-trend approach to develop an alternative forecast. Our assessment led us to accept Energex's proposed \$78.6 million in opex for annual metering charges (\$2014-15).

Based on our cost assessment of the individual building blocks and the requirement that Energex establishes separate annual charges, we do not accept Energex's proposed price caps for annual charges. Our substitute price caps are set out in Appendix A.

16.2.1.3 Upfront capital charges

Energex did not propose any upfront capital charges. We, however, consider their introduction to be economically efficient, with respect to new or upgraded connections. Upgraded connections refer to customer-initiated upgrades for alterations and additions (excluding solar PV) and upgrades of meter for solar PV. We have therefore included them in the structure of metering charges which we have accepted in this preliminary decision.

16.2.1.4 Meter exit fee

Our preliminary decision for switching customers to continue paying the capital component of the regulated annual metering charge removes the need for Energex to recover residual metering asset value through an upfront exit fee.

We do not approve Energex's proposal to recover administration costs relating to customers transferring to alternative metering providers through an exit fee. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

Therefore, no metering exit fee applies.

16.2.1.5 Control mechanism

Our preliminary decision is to apply price caps for individual type 5 and 6 metering services as the form of control. This means a schedule of prices is set for the first year. For the following year's the previous year's prices are adjusted by CPI and an X factor. The control mechanism formula is set out below:

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1

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

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

A_i^t is zero

X_i^t is:

for the annual metering charges, the factors set out in Table 16.6

for the upfront charges, the factors set out in Table 16.7.

Table 16.6 X-Factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	3.94	3.94	3.94	3.94

Source: AER analysis

Table 16.7 X-Factors for upfront capital charges (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
X factor	-0.22	-0.44	-0.43	-0.46	-0.22

Source: AER analysis

For the avoidance of doubt, when setting the prices for 2015–16, p_i^t are prices being set for year 2015–16 and p_i^{t-1} are prices from the year 2014–15.

We will check for compliance with the control mechanism during the annual pricing process. To be compliant, Energex must annually adjust individual price caps in accordance with the control mechanism formula shown above. Further, Energex must show that individual prices are less than or equal to the approved price cap for that individual service through providing a copy of their published price list for that year

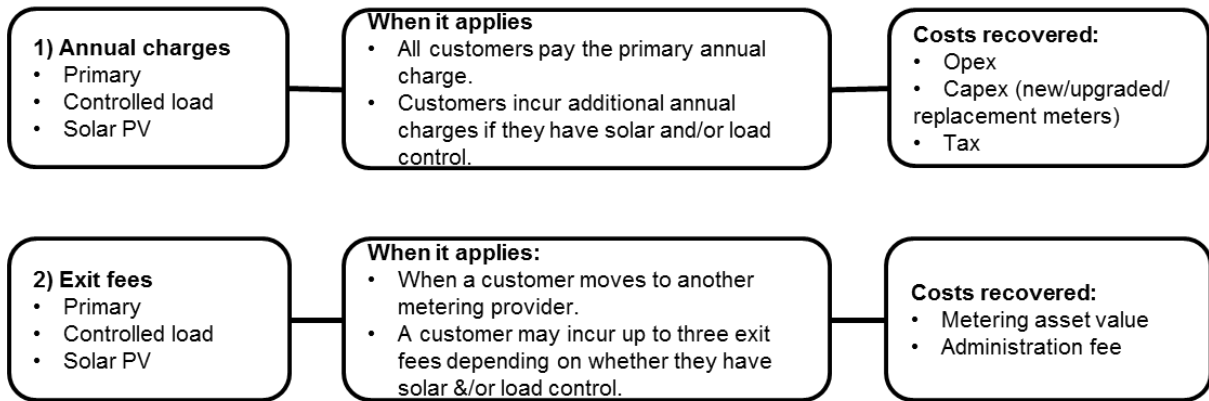
16.2.2 Energex's proposal

16.2.2.1 Structure of metering charges

Energex accepted our decision to classify type 6 metering services as alternative control services and to apply price caps for individual services as the control mechanism.³³ Figure 16.4 sets out the two types of metering services proposed by Energex. These are an annual metering service charge and an exit fee.

³³ Energex, Regulatory Proposal for the 2015–20 regulatory control period, October 2014, p. 272.

Figure 16.4- Proposed Metering Structure



Source: AER analysis

16.2.2.2 Annual metering services

Energex proposed three annual metering service charges, a primary metering tariff and two secondary metering tariffs for controlled load and solar PV customers. Table 16.8 sets out Energex's proposed charges in each year of the 2015–20 regulatory period.

Table 16.8 - Proposed annual metering service charges

\$/year, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Primary tariff	39.17	40.49	41.86	43.27	44.73
Controlled load	11.75	12.15	12.56	12.98	13.42
Solar PV	27.42	28.34	29.30	30.29	31.31

Source: Energex, *Regulatory Proposal for the 2015–20 regulatory control period*, October 2014, p 278, table 25.11

Energex used a limited building block approach to determine the revenue requirements that are the basis for the proposed price caps in Table 16.8. The proposed building block components are shown in Table 16.9.

Table 16.9 - Building block components for annual metering service charges

\$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	33.8	34.1	34.4	34.6	34.9
Return of capital	20.0	22.7	25.8	28.9	32.3
Opex	16.7	16.7	17.0	17.7	18.0

\$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Tax allowance	1.7	2.2	2.7	3.3	3.9
Unsmoothed revenue requirement	72.1	75.7	79.9	84.5	89.1

Source: Energex, *Regulatory Proposal for the 2015–20 regulatory control period*, October 2014, p. 276, table 25.9

Previously, all Type 6 metering assets were included in the RAB for standard control services. From 1 July 2015, Type 6 metering assets and supporting assets will be separated out into a MAB. Energex proposed an opening MAB value of \$435.9 million.³⁴

Energex have adopted straight line depreciation. Existing electronic (advanced) and electro-mechanical (accumulation) meter assets are assumed to have 15 year remaining lives.³⁵ Energex proposes to install only electronic meters in the forthcoming regulatory period and these new meters are assumed to have a 15 year standard life.³⁶

The proposed forecast capex is all inclusive for the installation and hardware associated with new connections, alterations and additions (excluding solar PV), upgrades of meter for solar PV and replacement.³⁷ All meters installed by Energex will be 'advanced meters' i.e. meters capable of being upgraded to a Type 4 remotely read meter. Energex have proposed replacing 200 000 meters that belong to meter populations that have unacceptable error proportions according to sampling it has undertaken.³⁸

Forecast opex was developed using base-step-trend methodology.³⁹ Revealed costs from a single base year, 2012-13, were used to determine the base. No step changes were applied.⁴⁰ This was trended forward by a factor of 1.7 per cent to account for a scaled output driver, cost escalation driver and an efficiency factor.⁴¹

Energex proposed limited demand growth of around 0.4 to 1.5 percent annually over the 2015–20 regulatory control period.⁴² This is due to forecast growth in metering services for new connections, alterations and additions (excluding solar PV) and replacement but a reduction in upgrade of meters for solar PV.⁴³ Energex have not

³⁴ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 275.

³⁵ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 275.

³⁶ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 275.

³⁷ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 272–3.

³⁸ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

³⁹ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

⁴⁰ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

⁴¹ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

⁴² Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

⁴³ Energex *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

forecast meter churn due to the uncertainty surrounding the development of contestability in metering. Instead, it proposed to make annual adjustments based on actual churn through the annual pricing process.⁴⁴

16.2.2.3 Metering exit fee

Energex have proposed three exit fees that will apply if a customer wants to change metering providers.

Table 16.10 - Proposed exit fees (\$2014–15)

\$ nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Primary tariff	290	297	306	315	324
Controlled load	109	112	116	120	124
Solar PV	31	32	34	36	38

Source: Energex, *Regulatory proposal: July 2015 to June 2020*, Appendix 60 Meter Pricing, October 2014, p 7, table 6.

The primary tariff and controlled load exit fee is comprised of the residual metering asset value and an administration cost. Energex proposed recovering the average depreciated value of removed metering assets through the exit fee. The rest of the MAB (such as shared and non-system assets) will be recovered through annual charges from remaining regulated metering customers. The administration component is the labour cost (inclusive of oncosts and overheads) for an administrative person's time (15 minutes) to process the customer transfer.

The solar PV exit fee is administration cost only. There is no recovery of metering asset value because there is no separate meter required for solar PV; the metering asset value will be recovered through the primary tariff exit fee.

16.2.3 AER's assessment approach

Our assessment approach first considered Energex's proposed structure of metering services. We then considered Energex's proposed costs, tailoring our assessment approach according to each type of charge.

16.2.3.1 Structure of metering charges

We considered Energex's proposed structure of metering services and whether it complies with our Framework and Approach.

⁴⁴ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

Our Framework and Approach, published in April 2014, sets out our proposed service classification and control mechanism for Energex's distribution services in the 2015–20 regulatory control period. In that way, it establishes a structure of metering services for which Energex's regulatory proposal should comply.

For type 5 and 6 metering services, our Framework and Approach specified an alternative control service classification.⁴⁵ It also stated that the control mechanism would be a cap on the price of individual services.⁴⁶ In making our assessment Energex's proposed structure of metering services, we considered these aspects of our Framework and Approach.

AEMC's draft rule change does not specify a method, but considered that the AER should determine how distributors recover residual capital costs of its regulated metering service in accordance with the existing regulatory framework.⁴⁷

We also considered requirements in the NER. In particular, the service classification and control mechanism factors.⁴⁸ They require us to consider whether it is more appropriate to allocate metering services costs through annual charges, upfront fees or network charges recovered from all customers. Table 16.11 sets out the factors which we have considered.

Table 16.11 Classification and control mechanism factors

Classification factors	Control mechanism factors
Potential for development of competition in the relevant market and how the classification might influence that potential	Potential for development of competition in the relevant market and how the control mechanism might influence that potential
The possible effects of classification on administrative costs of the AER, the distribution business and users or potential users	The possible effects of the control mechanism on administrative costs of the AER, the distribution business and users or potential users
The regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made	The regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
The desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)	The desirability of a consistent regulatory arrangements to similar services (both within and beyond the relevant jurisdiction)
The extent of the costs of providing the relevant service are directly attributable to the person to which the service is provided	Any other relevant factor
Any other relevant factor	

Source: NER, cl. 6.2.2(c) and cl. 6.2.5(d).

⁴⁵ AER, *Final framework for Energex and Ergon Energy*, April 2014, p. 52.

⁴⁶ AER, *Final framework for Energex and Ergon Energy*, April 2014, p. 45.

⁴⁷ AEMC, *Draft Rule Determination (Expanding competition in metering and related services)*, 26 March 2015, p 225

⁴⁸ NER, cl. 6.2.2(c) and cl. 6.2.5(d).

The desirability for consistency between regulatory approaches and arrangements is both a classification and control mechanism factor. In taking these factors into account, we considered our determinations on the NSW ACT 2014–15 and 2015–19 regulatory control periods. In those determinations we approved a structure of metering services which included separate charges for existing and new or upgraded customers.

We also had regard to the revenue and pricing principles in the national electricity law which include providing a distributor with a reasonable opportunity to recover at least its efficient costs.⁴⁹

16.2.3.2 Annual metering services

We assessed Energex's proposed operating and capital expenditure components associated with the annual metering service.

16.2.3.2.1 Opening metering asset base

In assessing the proposed opening metering asset base, we reviewed how Energex had separated its proposed opening metering asset base (MAB) as at 1 July 2015, from the RAB for standard control services.

16.2.3.2.2 Depreciation

We also considered the remaining asset lives Energex proposed and had regard to the opening of competition to metering services.

16.2.3.2.3 Forecast capital expenditure

In assessing the proposed forecast capital expenditure, we first considered any legislative or regulatory requirements regarding meter type and then reviewed Energex's 'unit costs' and 'volume forecasts'. More specifically, we assessed the proposed:

- 'material' and 'non-material' unit costs⁵⁰
- volume of 'reactive' and 'proactive' replacements.

16.2.3.2.4 Forecast operating expenditure

Operating expenditure refers to the operating, maintenance and other non-capital costs, including labour, incurred in the provision of metering services.

To develop our alternative forecast for metering opex, we used a top-down 'base, step and trend' approach which we explain further below.

⁴⁹ NEL, Revenue and Pricing Principles, 7A (2).

⁵⁰ Material costs relate to the hardware used to provide metering services. Non-material costs relate to the labour activities which Energex must perform in order to replace a meter.

16.2.3.2.4.1 Base

As operating expenditure is largely recurrent in nature, we considered Energex's historical costs to be a useful starting point to establish a base to forecast future costs. We also used benchmarking to assess the relative efficiency of the base year compared with comparable network businesses in the national electricity market.

Our base assessment uses historical data over a five year period, rather than selecting a single base year. Given that we do not apply an efficiency benefit sharing scheme (EBSS) to alternative control services, we consider an average of multiple years to be a better measure of a business' efficient base; it avoids any incentive to 'load' a single base year with expenditure going forward.

We used 'opex for metering' data collected in our economic benchmarking regulatory information notices (RIN). This audited data is suitable for comparison because the data provided by the distributors was prepared according to a consistent set of instructions and definitions.⁵¹

Our metering assessment relates to annual charges for default type 5 and 6 metering services common to all regulated metering customers. In some jurisdictions, there are also ancillary metering services paid for by customers specifically requesting a service like an off-cycle meter read or a meter accuracy test. However, the economic benchmarking metering opex data does not distinguish between ancillary and default metering services. Thus, we adjusted base metering operating expenditure data to exclude ancillary metering service costs so that our benchmarking analysis compares like for like data.

With this adjusted base data, we then performed our benchmarking analysis. We used a partial performance indicator for our benchmarking analysis. This compared historic annual metering opex per customer across non-Victorian distributors⁵² in the national electricity market.

Our benchmarking analysis for metering is a simpler version than what we used to assess standard control opex. This reflects the generally lighter handed regulatory approach to alternative control services compared with standard control services. For example, our econometric modelling results we used to assess standard control opex were based on data for network services and therefore do not strictly apply to metering services.

We then adjusted the benchmarking results for customer density. This is a network characteristic that is an exogenous influence on operating expenditure requirements.

⁵¹ AER, *Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample*, November 2013.

⁵² Victorian distributors rolled out advanced metering technology in the last regulatory period. These costs are not comparable to other distributors which have type 5 and 6 meters.

16.2.3.2.4.2 Step changes

When assessing a distributor's proposed step changes, we consider whether they are needed for the total opex forecast to reasonably reflect the opex criteria.⁵³ Our assessment approach is consistent with our *Expenditure forecast assessment guideline*.⁵⁴

We generally consider an efficient base level of opex is sufficient for a prudent and efficient distributor to meet all existing regulatory obligations. This is the same regardless of whether we forecast an efficient base level of opex based on the service provider's own costs or the efficient costs of comparable benchmark providers. We only include a step change in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex.

Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken.

16.2.3.2.4.3 Trend

We then trended forward base opex (plus any step changes) by considering forecast changes in output, price and productivity.

For both capital and operating expenditure, we had regard to the capital and operating expenditure objectives and criteria in chapter 6 of the NER.⁵⁵ Though these considerations relate to standard, as opposed to alternative, control services, they are helpful and relevant in providing a general framework for assessing a building block expenditure forecast. Among other things, when considering a distribution business's forecast, the capital and operating expenditure objectives and criteria state we should consider:

- the efficient costs required
- the costs a prudent operator would incur
- whether the proposed cost inputs are realistic.⁵⁶

16.2.3.3 Upfront capital charge

Energex did not propose any upfront capital charges. We nonetheless provided the distributor with an opportunity to comment on how such charges should be calculated.⁵⁷ Our preliminary decision took those comments into account, along with a

⁵³ NER, clause 6.5.6(c).

⁵⁴ AER, *Expenditure assessment forecast guideline*, November 2013, p.11, 24.

⁵⁵ NER, cll. 6.5.6 and 6.5.7.

⁵⁶ NER, cll. 6.5.6(c) and 6.5.7(c).

⁵⁷ Energex, AER Energex 039, Email dated: 15 April 2015.

report we received from Marsden Jacob. This report recommended the maximum material and non-material unit costs we should accept.

16.2.3.4 Meter exit fee

We considered the appropriate method to recover the residual metering asset value as part of our structure of metering charges assessment.

With regard to the administration component of the proposed exit fee, we must balance revenue recovery for the efficient costs of the distributor's service provision with identifying and removing barriers to entry and competition, consistent with the proposed metering rule change submitted by the COAG Energy Council and currently being deliberated by the Australian Energy Market Commission.⁵⁸

We undertook a cost assessment underlying the proposed meter transfer fees to determine the efficiency of those costs. To assess costs we considered the activities either required, or reasonably expected to be required, for a meter transfer, by both a distributor and a competing metering provider. We had regard to the costs estimated to be incurred from such activities in New South Wales, the Australian Capital Territory, Queensland and South Australia. Victorian distributors are under a State Government mandated smart meter roll out, and so meter transfer is not a comparable activity that can be presently undertaken and therefore benchmarked.

We consulted with first and second tier retailers and the Australian Energy Market Operator to ascertain those activities necessary for the efficient transfer of meter customers among service providers. The New South Wales and Australian Capital Territory distributors' revised revenue proposals, and the initial proposals from Queensland and South Australia's distributors, outlined the activities they would undertake to transfer customers.

16.2.4 Interrelationships

Our preliminary decision should provide Energex with an opportunity to recover at least its efficient costs.⁵⁹ This includes, where relevant, providing enough expenditure for the business to repay its debt financing costs and earn a reasonable return on its investments.

Our preliminary decision on Energex's alternative control metering proposal, therefore, interrelates with our assessment of its proposed rate of return. Refer to attachment 3 of this preliminary decision for the rate of return we accept for direct control services,⁶⁰ along with our reasons. Unlike standard control services, we will not be annually adjusting for the return on debt for alternative control services. The only annual

⁵⁸ Australian Energy Market Commission, Draft rule determination, Expanding competition in metering and related services, 26 March 2015.

⁵⁹ NEL, Revenue and Pricing Principles, 7A (2).

⁶⁰ Direct control services include standard and alternative control services.

changes for price caps for alternative control services will be consistent with our price control mechanism formula set out in 0.

Our preliminary decision for metering opex applies the real labour price changes and productivity used for standard control opex (attachment 7, see rate of change appendix).

16.2.5 Reasons for preliminary decision

Our reasons for not accepting Energex's proposed annual metering services charge and the transfer/exit fee are discussed in this section. We also set out our reasons for not accepting Energex's proposed structure of metering services.

16.2.5.1 Structure of metering charges

Our preliminary decision approves two types of charges:

- upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- annual charge comprising two components:
 - capital—metering asset base (MAB) recovery
 - non-capital—operating expenditure and tax.

We approve an upfront capital charge for two reasons. Firstly, it directly attributes the capital costs to the customer who initiates the meter installation. Secondly, it is appropriate in the context of expanding competition in metering. It is difficult to forecast the number of new regulated type 5 and 6 meters that will be installed in the upcoming 2015–20 regulatory control period. By charging upfront, we avoid having to forecast capital expenditure for new and upgraded metering installations that may not eventuate.

To better meet the distribution pricing principles, it important for annual charges to be set on a cost-reflective basis. It is particularly significant in the context of expanding competition in metering. Previously, metering was a standard control service and the related metering costs were bundled into general network tariffs. There was no transparency around the costs of providing regulated metering services. By setting cost-reflective regulated metering charges, customers will be able to compare the costs of their current regulated service with offers from alternative metering providers when competition begins.

We consider that a cost-reflective annual charge for new metering connections installed after 1 July 2015 should only consist of non-capital costs (operating expenditure and tax). This is because the capital cost of meters installed after 1 July 2015 would have been fully customer funded. In contrast, pre 30 June 2015 customers on a regulated type 5 or 6 metering service who have not paid for the meter upfront should contribute to the MAB recovery through their annual charge. That is, they pay a cost-reflective annual charge that includes both capital and non-capital components. This is the way such customers pay for their regulated metering services now.

However, if a customer chooses to switch to a competitive metering provider, the capital component of the annual charge would become stranded for the distributor. That is unless there is a mechanism for recovering that cost. It is important to recognise that customers pay the capital costs of a meter on an annual basis, they represent an amortised cost (that is, have been paid for upfront by the distributor and then recovered gradually over time from customers). Past capital expenditure is a fixed cost because it does not vary with how many customers switch; the capital costs have already been incurred by the distributor to provide a regulated metering service. This is in contrast to metering operating expenditure, such as meter reading costs, which are largely variable. This means the distributor can avoid those costs if a customer switches.⁶¹

QCOSS considers "*it would be inappropriate to recover residual costs associated with a service that customers are not getting any benefit from.... distributors should not be allowed to recover such costs from consumers - either through a charge which is allocated across all customers nor via individual exit fees.*"⁶² But this effectively means that the distributor would be unable to recover the undepreciated residual value of those meters. The revenue and pricing principles provide that distributors should have a reasonable opportunity to recover at least their efficient costs. We therefore consider it appropriate that distributors recover their fixed capital costs that were incurred in providing regulated metering services.

Accordingly, we considered the most appropriate way to recover metering capital costs incurred in providing regulated metering services that risk becoming stranded if a customer switches.

Energex proposed an upfront exit fee when a customer wished to switch to a competitive metering provider. This would ensure they recovered their metering capital costs for existing meters that would otherwise become stranded.

However various stakeholders raised concerns that a large upfront exit fee would be a barrier to competitive entry and to the take up of advanced metering.⁶³ In particular, it potentially creates a first mover disadvantage because a market-led smart meter rollout is predicated on the customer not having to pay any charges upfront.⁶⁴ Therefore, the first mover competitive metering provider may have to pay for both an

⁶¹ Although the capital costs of the meter remain to be recovered by the distributor, there is no longer any need to read the meter, thus providing an opex saving.

⁶² QCOSS, *Submission to AER Consultation Paper (Recovery of Residual Metering Costs)*, 31 March 2015, p 2

⁶³ Consumer Challenge Panel, *Updated submission on NSW DNSPs regulatory proposals 2014-19*, 15 August 2014, pp. 36-7.

Vector Limited, *Submission on DNSPs regulatory proposals*, 8 August 2014 p. 4.

ERAA, *Submission on Issues paper NSW electricity distribution regulatory proposals*, 8 August 2014, p. 2.

Origin Energy, *Submission on NSW electricity distributors regulatory proposal (attachment 1)*, 8 August 2014, p. 33.

AGL, *Submission on NSW electricity distribution networks regulatory proposals*, 8 August 2014, p. 21.

PIAC, *Submission on NSW electricity distribution network price determination*, 8 August 2014, p. 105.

⁶⁴ Vector Limited, *Submission on DNSPs regulatory proposals*, 8 August 2014 p. 4.

exit fee as well as the new smart meter—and bear the risk of those sunk costs if the customer decided to move to another competitive metering provider. We find that exit fees create a regulatory barrier to a market-led roll out of advanced metering.

There are several methods of ensuring distributors can recover capital costs incurred in providing regulated metering services. After extensive consultation with stakeholders⁶⁵, we decided on a method that we considered best balances the objectives of distributors and customers and meets regulatory objectives to promote competition in metering services.

Based on economic principles, the efficient investment signal to switch to unregulated metering would be to set individual exit fees based on the remaining economic value of the individual meter associated with the customer making the decision to switch. The remaining economic value would vary with the capability of the meter (the meter type) and remaining life (the age) of the meter. This would ensure that an existing meter would only be replaced if the new meter delivers sufficient additional economic value to cover its own cost and any remaining economic value of the existing regulated meter.

Although we considered that at a theoretical level this option has merit, at a practical level it has substantial shortcomings for a range of reasons. Firstly there is limited information as most distribution businesses do not record information about asset type or age at the individual customer level. Secondly, we are not satisfied that the amount distribution businesses are entitled to recover (based on actual costs) necessarily corresponds to the remaining economic value of a meter. For example, if a meter fails, distributors are still allowed to recover the capital costs that were incurred to provide that meter originally—even though the meter is no longer in service and therefore has no economic value. Also, regulated historic metering costs may not be efficient, as distribution businesses have not faced competitive pressures. Finally, we were concerned that it may be inappropriate to charge customers different exit fees that would vary with meter type and age because such investment decisions were made by distribution businesses, not customers.

We consider our preliminary decision to have switching customers continue to pay for the capital costs associated with the regulated metering service better meets the regulatory objectives under the NEL and NER, than Energex's proposal. We considered:

- Impact on competition
 - Our preliminary decision removes the upfront exit fee which was identified as the primary barrier to competitive entry by stakeholders

⁶⁵ In addition to our normal consultative process which allows stakeholders to provide submissions on the distributor's proposal and our draft decision, we also held a metering workshop on 11 September 2014 and released a consultation paper (on the alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge) in March 2015. We received submissions from consumer groups, potential competitive metering providers, retailers and distributors.

- Our preliminary decision removes concerns about first mover disadvantage that would arise if the first mover had to pay the upfront exit fee and risk being undercut by another competitive provider that does not face the exit fee. Under the preliminary decision, the customer is charged the capital component of the regulated annual metering charge directly.
- Administrative simplicity
 - Our preliminary decision makes use of existing information that Energex has, rather than relying on further information on the remaining economic or technical life of individual metering assets which would be difficult to determine.
- The directly attributed cost to minimise cross subsidies
 - Our preliminary decision involves continuing to charge switching customers an ongoing regulated annual charge to recover metering capital costs associated with their past regulated metering service. We considered whether it was appropriate to continue to charge a regulated annual charge when a customer is no longer receiving an active regulated metering service. We consider that it is appropriate to charge switched customers for fixed capital costs associated with their past regulated metering services because it more directly attributes cost recovery to the customer group that caused those costs to be incurred and ensures that the distributor has an opportunity to at least recover its efficient costs. We consider this also strikes an appropriate balance to promote efficient investment as set out in the revenue and pricing principles
 - Under our preliminary decision, only customers at premises which currently or previously had a type 5 or 6 metering service will be paying for the capital costs incurred in providing type 5 and 6 metering services
 - Nonetheless, our preliminary decision still involves some cross subsidy. This is because the capital component of the annual charge is based on the average depreciated value of the MAB. We consider this is appropriate given that we do not have granular information on the customer's specific meter asset type or age
 - Another form of cross subsidy is that the regulated annual charge (capital) a switching customer will pay for includes some recovery of forecast replacement capital expenditure that is not linked to the switched customer's past regulated metering service. The opening MAB value is based on past capital expenditure. The MAB is not forecast to grow much because from 1 July 2015, all new and upgraded meters will be paid for upfront and will therefore not be included in the MAB. However, some forecast capital expenditure relating to replacement meters will be added to the MAB.⁶⁶

⁶⁶ Capital expenditure related to replacement meters is added to the MAB and recovered from all metering customers through the annual charge, rather than charged upfront. We consider this is appropriate because replacement is

However, this is expected to be an interim issue as it is likely that distributors will not be able to install replacement meters after the metering rule change comes into effect on 1 July 2017⁶⁷

- Our preliminary decision to charge for new and upgraded meters upfront removes the risk of future cross subsidy. This is because by charging capital costs upfront, it is directly attributed and paid for by the customer choosing to install that meter. There is no risk of metering capital costs becoming stranded.

16.2.5.2 Annual metering services

Our preliminary decision is to not accept Energex's total proposed building block requirement for annual metering services. We accept a building block approach to setting charges but not accept the following components of Energex's proposal:

- opening MAB
- depreciation
- capex

This has led us to reject Energex's proposed annual metering service charges. Our alternative price caps are set out in appendix A.

16.2.5.2.1 Opening metering asset base

Our preliminary decision is to approve an opening MAB value as at 1 July 2015 of \$448.8 million and substitute it for Energex's proposed \$435.9 million (\$nominal).

To calculate the opening MAB, we reclassified metering assets to alternative control services. This is consistent with our F&A service classification⁶⁸ and Energex's proposal. In reclassifying metering assets, however, our preliminary decision differs to Energex's proposal in one respect. This is that we have moved certain load control assets (associated with new meter types) which Energex's proposal left in its RAB for standard control services. Our reasoning for moving those assets to the MAB is outlined in attachment 2.

We received submissions on Energex's proposed opening MAB. The Queensland Council of Social Services noted that the value of Energex's proposed MAB was disproportionately higher than Ergon Energy's MAB.⁶⁹ There are various reasons why the MABs of Energex and Ergon Energy can differ. For example, the amount of past capex and depreciation differs across both service providers. We do not currently have powers to review past capex on meters. This means a key driver behind Energex's

not initiated or controlled by the customer. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

⁶⁷ AEMC, *Expanding competition in metering and related services, Draft Rule Determination*, 26 March 2015, p. 79.

⁶⁸ AER, *Final framework and approach for Energex and Ergon Energy*, April 2014, p. 54.

⁶⁹ QCOSS, Submission on QLD regulatory proposals 2015–20, January 2015, p. 86.

relatively higher opening MAB cannot be reviewed as part of our regulatory processes. With regards to depreciation, Energex notes that some metering assets were previously reported as low voltage overhead service line assets, and thus attracted a lower depreciation rate (standard life of 35 years) than if they had been reported originally as metering assets (standard life of 25 years) which results in 'a higher book value than would otherwise be the case'.⁷⁰

We further note that QCOSS' submission identified an apparent discrepancy in Energex's proposed opening RAB and MAB values.⁷¹ We confirm that the opening MAB value of \$448.8 million (\$ nominal) has been subtracted from the opening RAB value set in this preliminary decision. There should, therefore, be no discrepancies.

16.2.5.2.2 Depreciation

We accept Energex's proposed standard metering asset life of 15 years.⁷² This establishes consistent economic and technical lifetimes for Energex's meters,⁷³ which we consider to be efficient. We also received submissions in support of this aspect of Energex's proposal.⁷⁴ There are also a small proportion of non-system assets in the MAB to reflect the use of metering services of these assets. The asset lives used to calculate depreciation for these assets are consistent with those for standard control services.

Our preliminary decision does not accept the proposed remaining asset lives. We have made adjustments to the remaining asset lives as at 1 July 2010 and actual net capex in relation to the standard control services RAB. This in turn impacted on the weighted average remaining lives of assets in the MAB at 1 July 2015. For more information about this, see attachment 2.

We also confirm that forecast, as opposed to actual, depreciation will apply to determining Energex's opening MAB at the commencement of the 2015–20 regulatory control period. This is consistent with our preliminary decision for standard control services.

16.2.5.2.3 Capex building block

Our preliminary decision accepts \$29.4 million in capex for annual metering services compared to Energex's proposed \$160.1 million (2014–15).

Most of the capex we have not approved in our preliminary decision (78 percent or \$101.4 million) relates to moving the cost recovery of new connections. This is from the annual metering service charge to upfront payments made directly to Energex by customers. As such, Energex should still recover its costs associated with new

⁷⁰ Energex, *Regulatory proposal: July 2015 to June 2020, Attachment 59: MAB methodology*, October 2014, p. 4.

⁷¹ QCOSS, *Submission on QLD regulatory proposals 2015–20*, January 2015, p. 86.

⁷² Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 275.

⁷³ Energex, *Regulatory proposal: July 2015 to June 2020, Attachment 59: MAB methodology*, October 2014, p. 4.

⁷⁴ QCOSS, *Submission on QLD regulatory proposals 2015–20*, January 2015, p. 90.

connections; however this will occur via a different capitalisation policy. Table 16.12 sets out Energex's proposed capex. It also shows our preliminary decision on each cost category.

Table 16.12 Proposed and substitute capex for metering annual services (\$ million 2014–15)

	Proposed	Unit cost adjustment	Volume adjustment	Preliminary decision
New connections	101.4	0.0	101.4	0.0
Replacement	58.7	0.0	29.3	29.4
Total	160.1	0.0	130.7	29.4

Source: Energex, *Regulatory proposal*, November 2014, p. 272; AER analysis.

16.2.5.2.3.1 Unit costs

Material unit costs

We accept Energex's proposed material unit costs. In reaching this preliminary decision, we took into account the jurisdictional requirements for which Energex must comply. We also assessed the proposed material unit costs against the market ranges our consultant, Marsden Jacob Associates, observed.

In Queensland, jurisdictional requirements specify that Energex must install type 5 interval meters. These meters must be upgradable for use in a type 4 smart metering installation.⁷⁵ Until upgraded, the interval meters are read by Energex on a type 6 accumulation basis.

We accept that the jurisdictional requirement is legally binding on Energex and must be complied with. In assessing the proposed unit costs we have, accordingly, not considered if it would be more prudent for Energex to install accumulation, instead of the proposed, interval meters.

- To assess the reasonableness of the proposed unit costs, we used a report commissioned from Marsden Jacob Associates. This report considered the 'maximum rate that should be applied for each meter hardware category based on consideration of the rates applied across the business and a comparison against current market rates'.⁷⁶ These rates were sourced from online advertised prices and through direct engagement with major suppliers.⁷⁷ Marsden Jacob took into

⁷⁵ AEMO, *Metrology Procedure: Part A National Electricity Market*, v3.20.

⁷⁶ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

⁷⁷ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

consideration volume discounts which would reasonably be expected to apply to metering hardware purchases.⁷⁸

Table 16.13 set out Energex's forecast material unit costs and Marsden Jacob's observations on current market rates. It also shows our preliminary decision on each proposed make and model of meter hardware.

Table 16.13 Energex's forecast material unit costs, Marsden Jacob Associates' observed market rates, and our substitutes (\$2014–15)

	Proposed	Marsden Jacob maximum	Preliminary decision
Single phase - one element	86.48	100.00	86.48
Single phase - two element	137.35	150.00	137.35
Multi phase (DC)	234.00	220.00	220.00
Multi phase (CT) - 2 man crew	474.23	Insufficient information	474.23

Source: Energex, AER Energex 014, Email dated 21 January 2015; Marsden Jacob Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.1.

Using the Marsden Jacob's report, we find that Energex's proposed unit costs are all within the observed market rates. This is except for the proposed unit cost for a multi-phase (DC) meter. We considered whether we should make an adjustment to Energex's capex building block because of this. However, we found that any such adjustment would be immaterial, given:

- we are only approving capex for meter replacements
- the low volume of multi-phase (DC) meters which are likely to be replaced in the 2015–20 regulatory control period.

Our preliminary decision to only accept capex for meter replacements, as part of the annual metering charge, is discussed further in section 16.2.5.4 below. We consider the establishment of upfront charges for new installations will facilitate competition in metering. We have therefore reallocated the cost recovery of new installations to upfront capital charges, leaving only the cost of replacements in the annual metering charge.

In finding that it is unlikely that Energex will engage in a significant volume of replacements involving multi-phase (DC) meters we had regard to the distributor's meter population. We observed that less than 5 percent of Energex's meters are of a multi-phase configuration. From this, we calculated that a capex adjustment to reduce Energex's proposed unit cost for a multi-phase (DC) meter would be immaterial. Too

⁷⁸ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

few of these meters are likely to be replaced to warrant any such adjustment and, hence, it has not been applied in this preliminary decision.

Non-material cost

In assessing Energex's proposed non-material unit costs we developed a range which we would be willing to accept. We also took the non-material unit costs of other non-Victorian distribution businesses in the national electricity market into account.

To devise our range for non-material unit cost, we applied a bottom up approach. This involved estimating a reasonable hourly rate for a metering technician and an average time required to replace a meter. We also accounted for the time it would take to travel from site to site. With regard to indirect costs, we took a conservative approach. This led to us developing a wide range for non-material unit costs which we would consider to be reasonable.

We accept Energex's non-material unit costs. It is within the limits we developed using our bottom up approach. In addition, it is among the lowest of the non-Victorian distribution businesses' non-material unit costs. We have not published the results of our analysis given that it contains commercially sensitive information.

16.2.5.2.3.2 Forecast volumes

We do not accept Energex's forecast volume of new connection. This is because our preliminary decision applies a different capitalisation policy to Energex's proposal. We also substitute Energex's proposed volume forecast for replacements. Table 16.14 sets out Energex's forecasts against our preliminary decision.

Table 16.14 Forecast and approved volumes of meter replacements

	Forecast	Preliminary decision
New connections	546 528	0
Replacements	200 000	100 155

Source: QLD Reset RIN 2015–20, October 2014; Energex, Regulatory proposal, Appendix 58, October 2014.

New connections

We do not accept any forecast volumes associated with new connections. Consistent with previous AER decisions,⁷⁹ we consider there to be substantial benefits if Energex changes its capitalisation policy. This is so that the costs of installing meters at new

⁷⁹ AER, *Draft decision on ActewAGL's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Ausgrid's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Essential Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014.

connections are not recovered through the annual metering charge, but as upfront payments.

Our preliminary decision is based on the AEMC's metering rule change.⁸⁰ When implemented, our approach to Energex's capitalisation policy for new connections (upfront payments) should help level the competitive playing field for new meters. This is by shifting how Energex's capital costs are recovered, from the annual metering services charge, where costs are smeared across all customers, to an upfront payment which new entrants to the market are able to compete with in terms of price.

This change in capitalisation policy for new connections has a significant impact on the capex building block component of annual metering charges. Notwithstanding this, Energex will still be able to recover its costs. The only difference is that the cost of new connections will be recovered via upfront capital contributions, rather than as part of annual metering charges.

We therefore do not approve any of the forecast 546 528 new connections. The charges our preliminary decision accepts for new connections are set out in Appendix A.

Replacements

Our preliminary decision is to not accept Energex's proposed volume forecast for meter replacements. We substitute Energex's proposed 200 000 replacements with 100 155, which we consider to be more reflective of the business' compliance obligations in the 2015–20 regulatory control period.

Energex's proposed replacement program is informed by regulatory obligations under the NER and Australian Standard 1284.13.⁸¹ Together these regulatory instruments create requirements on Energex to test the accuracy of its meters. More specifically, Chapter 7 of the NER establishes the maximum allowable overall error limits for a meter recording a customer's energy usage. For Type 5 meters this is an error reading of +/-1.5 percent at a full load.⁸² For Type 6 meters it is +/-2.0 percent.⁸³ Because it would be inefficient to test every meter in service against these error reading levels, Australian Standard 1284.13 establishes a process for taking 'samples' of a broader meter 'population'.

For example, if 1 201 meters of a particular make and model are in service, then Australian Standard 1284.13 requires that 125 sample tests have to be taken. This is to check their accuracy against the NER error limits. But if more meters of a different make and model are in service, then the sample size must be greater. For example, a population of 150 001 meters requires a sample size of 800.

⁸⁰ AEMC, *Draft rule determination: National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 March 2015.

⁸¹ Energex, *Response to AER Energex 039*, 9 February 2015, p. 2.

⁸² NER, S7.2.3.1.

⁸³ NER, S7.2.3.1.

When a set number of meters in a sample fail the NER accuracy limits, the entire population needs to be replaced in a time framework agreed to with AEMO.⁸⁴ The maximum number of fails which can occur before replacement is triggered is called the 'acceptable quality level'. This level is specified in Australian Standard 1284.13 and it varies according to the size of the meter population; the more meters in service, the greater the failure rate required.

In summary, Australian Standard 1284.13 and Chapter 7 of the NER create a rigorous regime for determining when replacement should occur. It establishes a statistical method to determine if there are too many meters in a population recording energy inaccurately such that the entire population can be said to have failed and should be replaced. Energex did not, however, follow the processes established under Australian Standard 1284.13 and Chapter 7 of the NER. Rather than testing for whether particular makes and models exceed their acceptable quality level, Energex grouped its samples together according to age.

Specifically, Energex conducted 10 000 tests to find if there are age groups of meters which do not comply with 'the **spirit** of AS 1284.13 and the overall installation error requirements according to the NER Chapter 7 (emphasis added)'.⁸⁵ Table 16.15 sets out Energex's findings. It includes information on the population size of each age group, the number of meters Energex tested and the proportion which failed the 2 percent accuracy limits for Type 6 meters. Figure 16.5 shows, in graphical form, the failure rates observed for each age group.

Table 16.15 Summary of Energex's sample testing

Age of meters (years)	Meter population	Number tested	Number failed	Proportion error (%)
65-70	6 700	44	14	31.81
60-65	9 517	375	115	30.67
55-60	2 668	214	54	25.23
50-55	13 293	168	14	8.33
45-50	67 977	757	122	16.11
40-45	106 810	1 747	68	3.89
35-40	91 198	1 399	76	5.43
30-35	Not provided	802	28	3.49
25-30	Not provided	1 147	9	0.70
20-25	Not provided	2 642	7	0.27

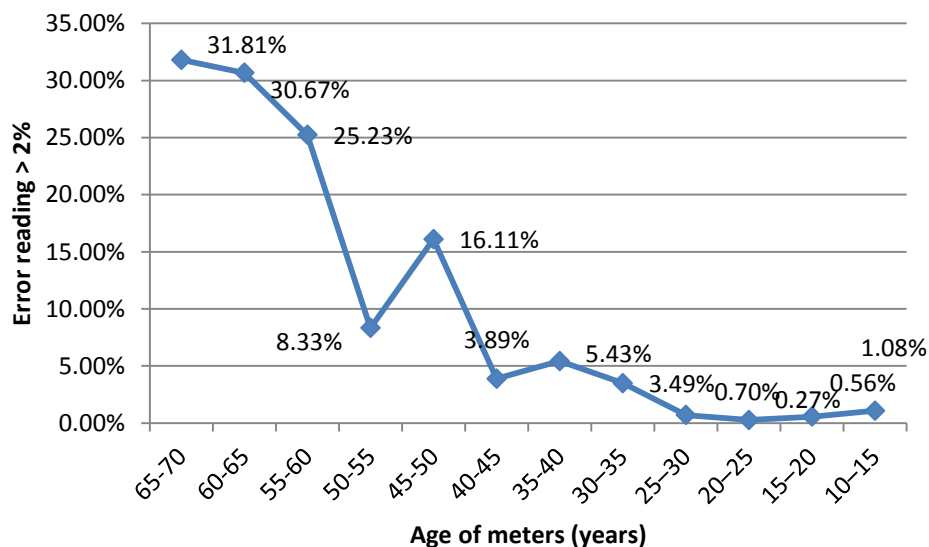
⁸⁴ NER, cl. 7.6.2.

⁸⁵ Energex, Regulatory proposal, Attachment 58, October 2014, p. 2.

Age of meters (years)	Meter population	Number tested	Number failed	Proportion error (%)
15–20	Not provided	535	3	0.56
10–15	Not provided	827	9	1.08

Source: Energex, *Regulatory proposal, Attachment 58*, October 2014, p. 2.

Figure 16.5 Energex's observed failure rates according to meter age



Source: Energex, *Regulatory proposal, Attachment 58*, October 2014, p. 2.

Taking Energex's sample testing into account, we accept that there appears to be a relationship between the age of a meter and its likelihood of failure. Our substitute forecast is nonetheless lower than the proposed amount. This is because of differences in the extent to which we consider the relationship put forward in Energex's proposal, extends into meters of a less advanced age.

We disagree with Energex that its sample testing shows that meters older than 35 years are likely to have more error readings than is tolerable under the 'spirit' of AS 1284.13 and the NER.⁸⁶ Out of the 91 198 meters in that age group Energex tested 1 399. It observed that 76, or 5.43 percent, exceed the maximum failure rate specified in the NER. On the basis of that analysis it considers all the meters from the 35–40 to the 65–70 age group should be replaced.⁸⁷

Our preliminary decision is that a failure rate of 5.43 percent, for meters in the 35–40 age group, is not sufficient to trigger the replacement of all meters within that age range or older. We reached this conclusion by assessing the required failure rates in

⁸⁶ Energex, *Regulatory proposal: July 2015 to June 2020, Attachment 58*, October 2014, p. 2.

⁸⁷ Energex, *Regulatory proposal, Attachment 58*, October 2014, p. 3.

Australian Standard 1284.13. To calculate those failure rates as a percentage, we divided the required sample size for each age group by the acceptable quality level for testing by variables.

Table 16.16 shows the results of our analysis. In summary, we found that meters in the 45–50 age group and above have a failure rate which is high enough to reasonably require their replacement. This results in a lower replacement forecast than Energex, which considers meters in the 35–40 age group and above should be replaced.

Table 16.16 AER analysis of failure rates

Age group	Required failure rate (%) under AS 1284.13	Observed failure rate (%)	Energex's proposed replacement	Our assessment
65-70	10.67	31.81	6 700	Accept
60-65	10.67	30.67	9 517	Accept
55-60	12.00	25.23	2 668	Accept
50-55	11.00	8.33	13 293	Accept
45-50	8.67	16.11	67 997	Accept
40-45	8.67	3.89	106 810	Not accept
35–40	8.67	5.43	91 198	Not accept
Total			298 163	100 155

Source: Australian Standard, AS 1284.13, 2002, p. 12; Energex, *Regulatory proposal, Attachment 58*, October 2014.

Note: Required failure rate calculated as the "acceptable quality limit + 1" in Australian Standard 1284.13 (table 2, page 12), divided by the sample size specified for the meter population of each age group.

Note: While Energex considers a total of 298 163 meters to have an unacceptable error proportion it has only proposed to replace 200 000 in the 2015–20 regulatory control period.⁸⁸

Our preliminary decision is therefore to approve a forecast volume of replacements equal to 100 155. We consider this forecast to provide Energex with a forecast volume which will allow the business to meet its regulatory obligations.

Finally, the substitute forecast we accept will allow Energex to meet its internal standards. Energex states that it has a policy where it will not tolerate any more than 4 percent of its meters being in error at any one time.⁸⁹ In the 2015–20 regulatory control period, Energex will have, on average, 2.18 million meters. By accepting a forecast volume of 100 155, we are in effect providing enough expenditure for Energex to replace 4.86 percent of its meter population. That is, our substitute accepts an amount in excess of Energex's 4 percent tolerance standard.

⁸⁸ Energex, *Response to AER Energex 039*, 9 February 2015, p. 3.

⁸⁹ Energex, *Regulatory proposal, Attachment 58*, October 2014, p. 1.

16.2.5.3 Opex

We accept Energex's proposed opex of \$78.6 million (\$2014–15). Our analysis found that Energex's opex proposal was relatively efficient.

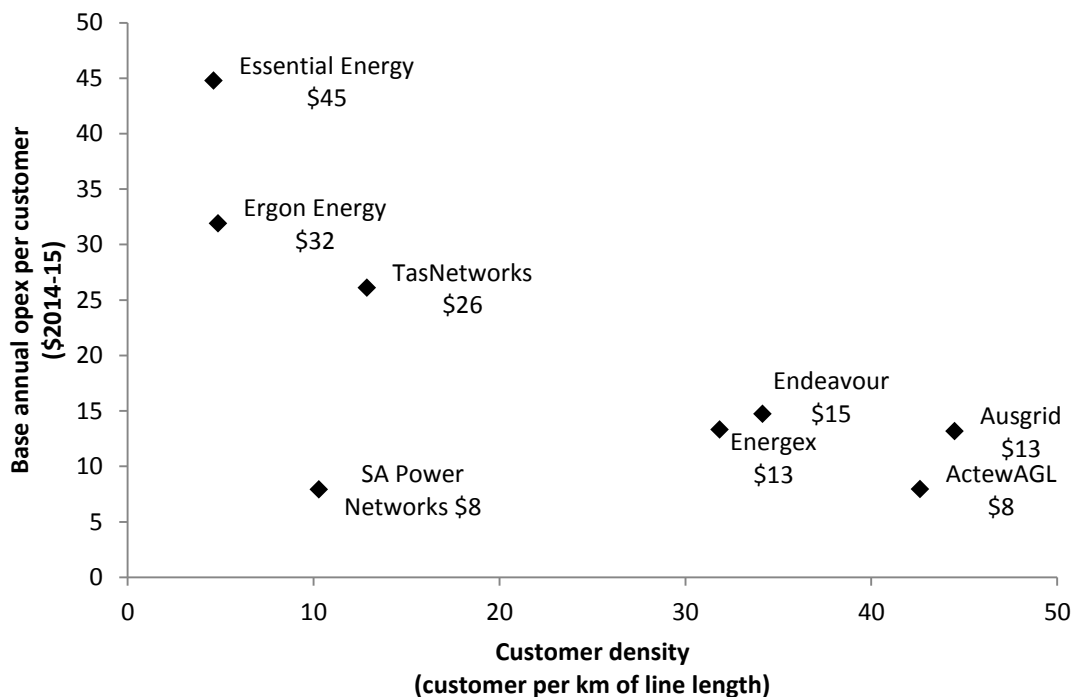
16.2.5.3.1.1 Forecast base

The initial step in our assessment of Energex's proposed opex was to consider its 'base' level of expenditure. We looked at what Energex's base should be, from two different perspectives. These were Energex's historical opex and its performance against benchmarking.

With assessing historical expenditure, we consider Energex's base should be at least as efficient as its costs in previous years. We observed Energex's historic opex over a five year period. Applying this approach, we observed a base expenditure of \$13 per customer per year (\$2014–15).

When comparing Energex's proposed opex to its peers, we normalised our results by accounting for customer density. We calculated this as the number of customers a distribution business has per kilometre of line length. We took customer density into account because, all things equal, businesses with a low customer density are likely to require higher opex. For example, this could be because of longer travel times to service customers. Figure 16.6 shows the results of our benchmarking.

Figure 16.6 Benchmarking of annual metering opex per customer (\$ 2014–15)



Source: AER analysis

We observe a strong correlation between customer density and costs, and so we can reasonably expect Energex to require no more opex per customer than a distribution business with a similarly dense network. Taking this approach, we consider Endeavour Energy to be a relevant comparator for Ergon Energy. This is because the two distributors have similar customer density.

However, our benchmarking results show that Energex historical opex is relatively efficient compared to Endeavour Energy, which has the same customer density.⁹⁰ As a consequence, we have decided not make an efficiency related adjustment to its base opex.

We have therefore used Energex's historical opex of \$13 per customer/year as the base for setting forecast opex in the 2015-20 regulatory control period.

16.2.5.3.1.2 Step changes

Energex did not propose any step changes.⁹¹ Nor did we consider any other positive or negative step changes should be applied to Energex's base opex.

16.2.5.3.1.3 Trend

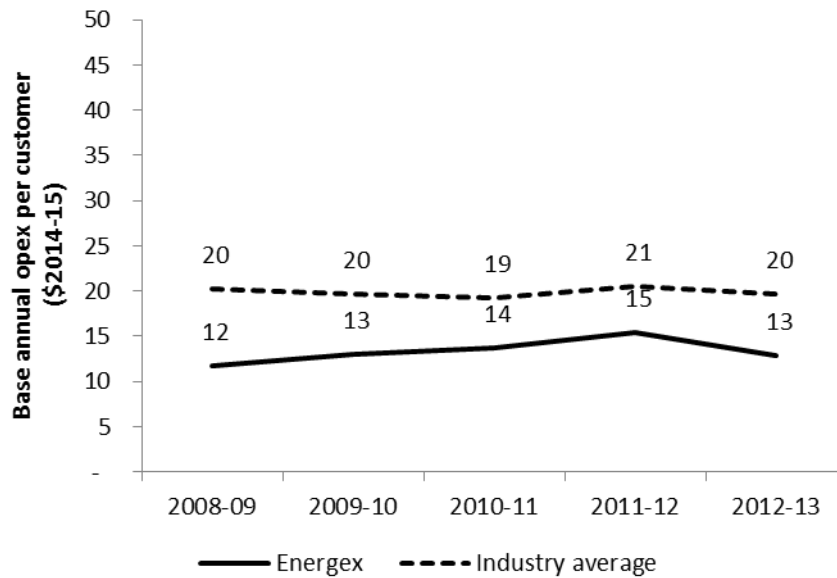
We trended the base forward for forecast metering customer growth. We have applied zero forecast real price and productivity growth.

Our analysis for base metering opex used average data from 2008–09 to 2012–13. One would expect to see metering opex per customer increasing over the period if there was real price growth.

⁹⁰ This not to say that Energex is as efficient as it could be; benchmarking only shows the relative efficiency across firms.

⁹¹ Energex, *Regulatory proposal: July 2015 to June 2020*, October 2014, p. 273.

Figure 16.7 Annual default metering opex per customer



Source: AER analysis

Figure 16.7, however, shows that Energex's metering opex was generally stable over the period, which is consistent with the industry average. This implies that either there were no real price increases over this period, or the distributors were able to offset these real price increases with productivity improvements.

Given that opex is largely recurrent and metering opex per customer did not trend upwards over the 2008–09 to 2012–13 period, we do not forecast metering opex per customer to increase in the 2015–20 regulatory control period. Therefore, we apply zero real price and productivity growth.

Our alternative forecast arrived at \$94.9m (\$ 2014–15). Energex's proposed opex is below our alternative forecast. We therefore accept Energex's proposed opex for metering services of \$78.6m.

16.2.5.4 Upfront capital charge

Energex's proposal did not include any upfront charges. Our preliminary decision, however, is to move the cost recovery of new connections from the annual metering service charge to an upfront payment, made directly by customers to Energex at the time of installation.

16.2.5.4.1 Policy reasons

By moving the cost recovery of new connections, we have amended Energex's proposed structure of metering services. In making this preliminary decision we had regard to certain factors (see 16.2.3.1). These include:

- how the control mechanism may influence the potential for competition in unregulated metering

- the regulatory arrangements that applied in the most recent distribution determination
- the desirability for consistency of regulatory arrangements for similar.
- With regard to the desirability for consistency, we took into account our draft determinations on the NSW ACT 2014–15 and 2015–19 regulatory control periods.⁹² In those draft determinations we approved a structure of metering services which included separate charges for existing and new/upgraded customers.

We consider the same approach should be applied in Queensland, with respect to the cost recovery of new connections made by Energex (and Ergon Energy). As noted in the section above, this preliminary decision is principally driven by the AEMC's metering rule change. When implemented, our approach to Energex's capitalisation policy for new connections (upfront payments) should help level the competitive playing field for new meters. This is by shifting how Energex's capital costs are recovered, from the annual metering services charge, where costs are smeared across all customers, to an upfront payment which new entrants to the market are able to compete with in terms of price.

We also had regard to the revenue and pricing principles in the national electricity law which include providing a distributor with a reasonable opportunity to recover at least its efficient costs.⁹³ On this requirement, we note that Energex proposed \$101.4 million (2014–15) for new connections in the 2015–20 regulatory control period, which we are not accepting. Notwithstanding, Energex will still be able to recover its efficient costs, as required under the revenue and pricing principles. However, this will be via a different capitalisation policy; that is, via an upfront payment, as opposed to through the annual metering charge.

16.2.5.4.2 Calculation of upfront charge

We consulted with Energex about how the upfront capital charge for new installations should be calculated. In response to an information request, Energex put forward a proposal for how this should be done.⁹⁴ We assessed this proposal against advice we received from Marsden Jacob about efficient material and non-material unit costs, as well as the consultant's advice on overhead and on-cost adjustments.

16.2.5.4.2.1 Material unit costs

We accept the majority of Energex's proposed material unit costs. We also accept each of the proposed on-costs and overhead adjustments. Table 16.17 sets out

⁹² AER, *Draft decision on ActewAGL's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Ausgrid's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Essential Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014.

⁹³ NEL, Revenue and Pricing Principles, 7A (2).

⁹⁴ Energex, Email to the AER, 15 April 2015.

Energex's proposed calculation of the material components of the upfront capital charge. It also shows the maximum rates Marsden Jacob recommended that we accept for these components, along with our preliminary decision.

Table 16.17 Proposed calculation of upfront charge (material)

	Proposed	Marsden Jacob maximum	Preliminary decision
<u>Unit costs (\$ 2014–15)</u>			
Single phase - one element	86.48	100.00	86.48
Single phase - two element	137.35	150.00	137.35
Multi phase (DC)	234.00	220.00	220.00
Multi phase (CT) - 2 man crew	474.23	Insufficient information	474.23
<u>On-costs and overhead rates</u>			
Material on-costs	4.6 percent	7.25 percent	4.6
Capital allowance	27.0 percent	Not assessed	27.0

Source: Energex, AER Energex 039, Email dated 15 April 2015; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

Our preliminary decision accepts all the proposed unit costs for metering hardware. This is except for the cost of a multi-phase (DC) meter which exceeded Marsden Jacob's maximum range.⁹⁵ In place of the proposed \$234 for that particular meter, we substitute a unit cost of \$220.

We accept Energex's proposed material on-cost of 4.6 percent. It falls within the range Marsden Jacobs has advised us as being reasonable.⁹⁶ We also accept that the shifting of the cost recovery of new connections to upfront charges requires the application of a capital allowance. While we have not received advice from Marsden Jacobs on this aspect of Energex's proposal, we consider the rate that it has proposed to be reasonable. We therefore accept that aspect of Energex's proposal.

16.2.5.4.2.2 Non-material unit costs

We accept each of the components making up Energex's calculation of the non-material component of the upfront capital charge. Table 16.18 sets out each aspect of Energex's proposed calculation and our preliminary decision regarding them.

⁹⁵ Marsden Jacob Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.1.

⁹⁶ Marsden Jacob Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.2.

Table 16.18 Proposed calculation of upfront charge (non-material)

	Proposed	Marsden Jacob Maximum	Preliminary decision
<u>Unit costs (\$ 2014–15)</u>			
Labour rate (\$/hour) – including labour on-costs	71.07	89.92	71.07
<u>On-costs and overhead rates</u>			
General overhead	44.1 percent	59.0 percent	44.1 percent
Fleet on-costs	12.6 percent	Not assessed	12.6 percent

Source: Energex, AER Energex 039, Email dated 15 April 2015; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014.

With respect to the non-material component, Energex proposed a labour rate, inclusive of labour related on-costs such as annual leave loading and superannuation, of \$71.07 (\$2014–15). We consider this amount to be reasonable. It fits within the maximum labour rate for a technician which Marsden Jacob considered to be reasonable. This maximum rate was \$89.82 (2014–15), which was derived from a raw labour rate of \$59 plus an on-cost adjustment of 52.23 percent.⁹⁷

Energex also proposed the application of a general overhead factor of 44.1 percent to the labour rate of \$71.07 (2014–15). We accept Energex's proposed adjustment. It is less than the Marsden Jacob maximum rate of 56.0 percent.

Additionally, Energex's proposed a fleet on-costs factor of 12.6 percent. This is intended to recover the costs associated with 'motor vehicle leasing and internal fleet operating, management and administration costs'.⁹⁸ We accept this aspect of Energex's proposal as well. When the percentage adjustment (12.6 percent) is added to the proposed general overheads adjustment (44.1 percent) the total adjustment is still less than Marsden Jacob's maximum rate (59 percent). We therefore do not consider this aspect of Energex's proposal to be overstated.

16.2.5.4.2.3 Approved upfront charges

Our preliminary decision is to accept how Energex proposed to calculate the upfront capital charge. This is with the exception of our preliminary decision to substitute the material unit cost of a multi-phase (DC) meter. This brings it within the maximum limits Marsden Jacobs recommended. For all other meters, we have accepted Energex's proposal for calculating the upfront capital charge.

⁹⁷ Marsden Jacob Associates, Consultant report to the AER on Alternative Control Services, October 2014, Appendix 2, Table 13.

⁹⁸ Energex, Cost allocation method, 1 July 2015, p. 18.

We have determined that the upfront capital charge should be annually adjusted for labour price changes. In coming to this conclusion, we note that our preliminary decision has determined that ancillary service fees will be subject to such annual adjustments. The upfront capital charge recovers similar costs to ancillary services fees. It follows that labour price changes should be accounted for in our price control for the upfront capital charge. We have done this in our control mechanism decision in section 0 above.

Not all of the costs associated with the upfront capital charge relate to labour. To take this into account, when making our price control decision we have used a weighted X-factor. Specifically, we observed that about 60 percent of the costs relating to the upfront capital charge are attributable to labour. In setting the X-factor, we therefore applied a weighting of 60 percent to the labour price changes, which we have forecast in this preliminary decision.⁹⁹

The approved upfront capital charges are set out in Appendix A.

16.2.5.5 Meter exit fee

Our preliminary decision to continue charging switched customer for the capital component of the annual metering charge. Therefore, there is no risk of stranded assets that need to be recovered through an exit fee.

We do not approve Energex's proposal to recover administration costs relating to customers transferring to alternative metering providers through an exit fee. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

In assessing all distributors' proposed meter transfer fees, our main focus is on the types of activities that are undertaken by retailers, distributors and metering providers in the National Electricity Market when a customer churns from a distributor owned meter. We also looked at the methodologies distributors adopted to establish the fee. Furthermore, because there is an alternative provider to that of the distributor, those providers' approach to dealing with customer meter churn and any associated costs should provide a direct comparator for that of the monopoly business.¹⁰⁰

Retailers submitted that any activities undertaken by the distributors was no different from existing data entry/system management functions undertaken as part of normal business practice and that any incremental costs associated with 'administration' would be absorbed by the entity acquiring the metering customer.¹⁰¹

⁹⁹ See attachment 2 of this preliminary decision for more information on how changes in labour costs were forecast.

¹⁰⁰ Retailers in the National Electricity Market can and do provide metering services to the contestable elements of the market, namely the medium and large businesses. Distributors at this stage maintain a monopoly provision to household customers but this will change with advent of the AEMC competition in metering rule change.

¹⁰¹ Vector Limited, submission on the AER's draft decision on New South Wales and ACT Electricity Distributors' Regulatory Proposals for 2015–16 to 2019–20, pp. 5, 6-8, 13 February 2015, p.p. 6-7; AGL, Alternative approach to the recovery of the residual metering capital costs through an alternative control service annual charge, 27

Oakley Greenwood, in its report to Origin Energy corroborated stakeholders views by contending that changing information in the distributors systems, is likely limited to a change in information about the entity that is responsible for the meter; the identity of the metering coordinator; and sufficient information about meter type to enable its verification for tariff assignment, was probably all that was required.¹⁰²

We tested this with retailers, many of whom are already providing metering services to large customers, which is a contestable market. Simply Energy did not agree with the imposition of administration fees; nor did Origin Energy. The latter was concerned that all three NSW distributors used vastly different inputs and therefore required testing against efficient benchmarks before a reasonable costs could be determined.¹⁰³ The retailer considered that a consistent approach to the calculation of administrative costs was most appropriate.¹⁰⁴

Simply Energy observed their current role in churning meters (type 4) in the competitively provided commercial market involved administrative transaction costs that were immaterial to it. They also advised that distributors were not currently charging them a meter transfer fee where the customer switched from the distributor to the retailer as metering provider.¹⁰⁵

Commenting on the New South Wales distributors proposals, Simply Energy stated that there appeared no assumption of batch processing. Instead, the proposed charges assumed each meter was being processed individually. Simply Energy noted that if put in the position of the distributors, it would review processes in detail to determine the optimum batch size, which would be at least 20 meters (i.e. customers) per batch.¹⁰⁶ In such circumstances, multiplying Endeavour Energy's proposed five minutes per meter by 20 minutes equates to 100 minutes per batch for each manual process. Simply Energy proposed that 10 minutes was a more credible time.¹⁰⁷ This was also appropriate for other distributors.

Furthermore, Simply Energy advised that the reasonable activities it would have to incur to process a batch of 20 meters and the time taken for each were:

- Meter provider database update—10 minutes
- Banner system meter update—25 minutes
- Metering business system update—25 minutes

March 2015, p.2; AGL, email to AER staff, AGL Presentation to AER staff—metering regulation & transition to competition, 13 March 2015.

¹⁰² Oakley Greenwood, Review of NSW DBs Regulatory Submission, 8 August 2014, p. 7 in Origin Energy, Submission to NSW Electricity distributors' regulatory proposals, 8 August 2014, (attachment 2).

¹⁰³ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 1)p. 36.

¹⁰⁴ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 2), p. 7.

¹⁰⁵ Meeting between respective staff of Simply Energy and AER on 16 March 2015.

¹⁰⁶ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

¹⁰⁷ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

- Banner system final read update—10 minutes.¹⁰⁸

This amounts to 70 minutes for a batch of 20 meters; or a total time per meter of 3.5 minutes. This is substantially less than the times proposed by any of the distributors. Given this, Simply Energy submitted that the imposition of a meter transfer fee in the residential metering market of the magnitude distributors had proposed was not justified. Rather, Simply Energy argued that the administrative costs are negligible.

Retailers as the acquirers of a new meter customer bear the costs of acquisition and must provide all relevant information to the entity that has lost the customer, in this case the distributor. This includes attending the site, removing the meter and sending it to the distributor's depot or alternative location. The retailer has an incentive to keep those costs down and to work with the business that has lost the customer—be they distributors or other retail rivals once a competitive market is established—to ensure smooth market operation. This has been the case since inception of the national electricity market for large customers. We do not find that the costs proposed by the distributors are reflective of this cost minimisation incentive.

This is confirmed by the Australian Energy Market Operator who has a new set of meter churn procedures due to commence September 2015.¹⁰⁹ This new procedure simplifies the meter churn procedure and places the onus on the Financial Responsible Market Participant (as the incoming Responsible Person) and their Metering Provider to update Market Settlement and Transfer Solutions and administer the transfer. The distributor's role is minimised, especially for the displacement of Type 6 legacy meters. Type 5 meters will require a final read. It could be expected that competing meter providers will be sufficiently encouraged to work with distributors to provide them with the necessary final read data. This is because to do otherwise will reduce their profit margins and potentially put them at risk of failing to meet their obligations to provide relevant data to ensure market settlement in a timely manner.¹¹⁰ It is reasonable to assume that the new meter churn procedures will carry forward into the residential metering market, the competitive metering element of which is now in its infancy.

As a metering provider with experience in competitive metering markets, Vector commented on Endeavour Energy's cost assumptions in its revised revenue proposal. These are reproduced in Table 16.19 where both organisations responses can be compared.

¹⁰⁸ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

¹⁰⁹ See <http://www.aemo.com.au/Consultations/National-Electricity-Market/Second-Stage-Notice-of-Consultation--Meter-Churn-Package>, accessed 26 March 2015 and <http://www.aemo.com.au/Consultations/National-Electricity-Market/~media/Files/Other/consultations/gas/Churn%20Package%202014/Meter%20Churn%20Procedure%20FRMP%20v10%20clean.ashx> accessed 26 March 2015.

¹¹⁰ We are aware of instances where some distributors are alleged to have deliberately stalled or frustrated attempts by large commercial users to switch meter provider. However, this is a separate issue of specific business conduct, rather than of efficient billing systems per se.

Table 16.19 Endeavour Energy meter transfer fee build up and Vector response

Endeavour Energy Task	Endeavour Energy Time	Vector Comment
Administration Officer updates the meter removal in the Meter Provider Database.	5 min	Valid distributor activity that is currently carried out regularly now. Could not be delivered by Metering Service Provider but could be automated via distributor integration to market systems
Network Billing Data Analyst updates the meter removal and the new metering details (for the non-Endeavour Energy asset) in the Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Network Billing Data Analyst updates the new metering details in the Metering Business System (MBS), which will allow network billing activities to occur.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Metering Officer obtains the final read for the meter and inputs the details of the final read into Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly
The ASP returns the Endeavour Energy removed asset back to the designated Endeavour Energy depot. Endeavour Energy process dictates that the meter is double bagged and goose necked to ensure safe transportation of asbestos contaminated materials. The consumables required to meet these requirements are supplied by Endeavour Energy.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.
Cost of meter disposal.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.

Source: Endeavour Energy; Vector Limited.

Vector advised that their response to the activities listed in **Error! Reference source not found.** was that the tasks were not unique to distributors. Alternative meter service providers can now, and will in the future, undertake many of these tasks. Furthermore, they noted that Endeavour Energy could integrate these activities and tasks with electronic transactions that they presently receive from AEMO.¹¹¹ Vector says this is how it operates in the market today and did not see why distributors should not do the same. Given that distributors were performing these functions now as standard business practice, Vector could not anticipate what incremental costs would arise as a result of competitive metering.¹¹²

¹¹¹ Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

¹¹² Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015

We do not agree with the distributors' position that that an increase in staff will be required within the regulatory periods commencing 1 July 2015. We also find that it will be the meter service provider, as the financially responsible market participant, who will bear the additional costs associated with meter churn, not the distributors.

We find that customers would not be paying an efficient level of costs for meter churn if the distributors proposed transfer fees were approved. A meter transfer fee of the order proposed by Energex (\$31 to \$38) could amount to a de-facto exit fee that would act as a barrier to competition and the uptake of new advanced meters. While the national electricity law requires us to ensure distributors have the opportunity to recover at least their efficient costs we are not persuaded by the evidence that distributors have material incremental costs to recover in amending records to take account of customer churn. Any incremental costs will be borne by the acquirer of the new meter customer—at the moment, retailers. Furthermore it is noteworthy that distributors are churning type 6 meters for interval meters for customers installing Solar Photovoltaic systems in large numbers without imposing any administrative fees for the meter transfer.

Further support to our findings that the proposed transfer fees are disproportionate to the activities to be undertaken is in comparing the per customer meter opex fee which we have approved in this decision. Our preliminary decision accepts Energex's proposal to recover \$11 annually for metering opex per customer for meter data services, truck rolls, reading and processing, a share of information technology costs and including overheads. It does not follow that a proposed transfer fee greater than this is reasonable.

We do not approve a meter transfer fee for the regulatory control period commencing 1 July 2015.

16.2.5.6 Control mechanism

Our preliminary decision applies the control mechanism which we proposed in our final Framework and Approach for Energex.¹¹³

We used X-factors to smooth annual price movements. It does not include any real price escalators. This is because we assessed whether any real price escalators should apply as part of our building block revenue assessment.

The X-factors for the upfront capital charges account for real labour price escalation.

The approved control mechanism includes an 'A-Factor'. In our final Framework and Approach we stated that A-Factor could be used to adjust for 'residual charges when customers choose to replace assets before the end of their economic life'.¹¹⁴ Our preliminary decision, however, establishes a metering tariff structure which does not

¹¹³ AER, *Final Framework and Approach for Ergon Energy and Energex*, April 2014, p. 96–97.

¹¹⁴ AER, *Final Framework and Approach for Ergon Energy and Energex*, April 2014, p. 96–97.

result in such residual charges.¹¹⁵ Consequently, the price control we have specified as apply to Energex has been set to zero. See section 0 for further details.

16.3 Public lighting

16.3.1 Preliminary decision

We do not approve Energex's proposed public lighting charges because we have determined;

- a nominal post-tax WACC of 5.85 per cent instead of the proposed 7.75 per cent
- imputation credit assumption of 40 per cent instead of the proposed 25 per cent

In all other respects we have approved Energex's proposal.

Form of control

Our preliminary decision is to apply a price cap for the form of control to public lighting, consistent with the final F&A. Figure 16.8 sets out the control mechanism formulas for public lighting.

Figure 16.8 Public lighting formula

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1.

p_i^t is the cap on the price of service i in year t. However, for 2015-16 this is the price as determined in Table 16.22.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

X_i^t is the value of X for the year t in the regulatory control period. There are no X-factors for public lighting.

¹¹⁵ An A-factor could have been used to increase the regulated annual charge for remaining regulated customers to recover stranded assets arising from other customers switching to competitive providers. However, our preliminary decision is for switched customers continue to pay the regulated annual charge (capital) until the MAB is fully depreciated. This removes the need to make A-factor adjustments to the regulated annual charges of remaining customers.

A_i^t is an adjustment factor likely to include, but not limited to, adjustments for residual charges when customers choose to replace assets before the end of their economic life. For public lighting we consider the value for A is zero.

16.3.2 Energex’s proposal

Energex proposes the continuation of its charges being broken down into:

- major light charge for luminaires owned and operated by the Energex (EOO)
- minor light charge for luminaires owned and operated by the Energex (EOO)
- major light charge for luminaires gifted to the distributor by a council but operated by Energex (GOO)
- minor light charge for luminaires gifted to the distributor by a council but operated by Energex (GOO)

Energex's proposed prices are set out in Table 16.20.

Table 16.20 Proposed prices for public lights, \$ per day

	2015—16	2016—17	2017—18	2018—19	2019—20
EO&O - Major	0.88	0.90	0.92	0.95	0.97
EO&O - Minor	0.28	0.29	0.29	0.30	0.31
GO&O - Major	0.40	0.41	0.42	0.43	0.44
GO&O - Minor	0.13	0.14	0.14	0.15	0.15

Source: Energex, 2015-20 Regulatory Proposal, p 291, table 26.11

16.3.3 Assessment approach

The AER has continued with the assessment approach used in New South Wales distributors' public lighting proposals. This involves assessing Queensland distributor's public lighting proposals using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

16.3.4 Submissions

The Local Government Association of Queensland notes a reduction in prices in the first year of the regulatory control period and increase in line with inflation for the remaining years thereafter.¹¹⁶ They have no issue with this.

¹¹⁶ LGAQ Submission, 30 January 2015.

The LGAQ also raises the issue of end of life treatment of assets and unpredictable costs for councils. This was in relation to councils potentially purchasing the distributors public lighting assets and the costs associated with doing so.

16.3.5 Reasons for preliminary decision

The reasons for the nominal post-tax WACC of 5.85 per cent and imputation credit assumption of 40 per cent instead are discussed in rate of return, attachment 3.

The issue of the end of life treatment of assets should continue to be worked through in the discussions between distributors and councils to seek an agreed approach. Energex did not propose anything in relation to the treatment of the end of life of assets.

The preliminary decision implements revenue decrease in 2015-16 by 19.3 per cent compared to a proposed decrease of 10 per cent. Preliminary decision revenue is set out in Table 16.21.

Table 16.21 Total revenue, millions

	2015—6	2016—17	2017—18	2018—19	2019—20
Proposed	39.4	40.4	42.0	43.8	45.1
Preliminary decision	35.8	36.7	38.4	40.1	41.3
change from previous year (percentage)	-19.3	2.6	4.4	4.5	3.1

Source: AER analysis.

Preliminary decision prices for each light type are set out in Table 16.22.

Table 16.22 Preliminary decision prices for public lights, \$ day

	2015—16	2016—17	2017—18	2018—19	2019—20
EO&O - Major	0.78	0.80	0.82	0.83	0.85
EO&O - Minor	0.27	0.28	0.28	0.29	0.30
GO&O - Major	0.36	0.37	0.37	0.38	0.39
GO&O - Minor	0.13	0.13	0.14	0.14	0.14

Source: AER Analysis

A Approved charges

A.1 Ancillary network services

Table 16.23 Ancillary network services, preliminary decision

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Application services to assess connection application and making of compliant connection offer.	Large Customer Connections	Quoted Example Only	5,198.14	5,198.14	-
Undertaking design for small customer or real estate development (sub-division) connection offer (excludes detailed design undertaken after a connection offer has been accepted)	Real Estate development (sub-division)	Quoted Example Only	7,147.44	7,147.44	-
Carrying out planning studies and analysis relating to distribution connection applications (including sub-transmission and dual function assets)	Large generators or loads that require feeders that may trigger transmission or distribution works	Quoted Example Only	9,478.88	9,478.88	-
Feasibility and concept scoping, including planning and design, for large customer connections.	Large Customer Connections	Quoted Example Only	3,574.47	3,574.47	-
Negotiation services involved in negotiating a connection agreement - complex	Large Customer Connections	Quoted Example Only	1,516.62	1,516.62	-
Negotiation	Standard jobs for	Price Cap	1,516.62	1,516.62	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
services involved in negotiating a connection agreement - simple	Small Customer Connections and Real Estate Developments (sub-divisions). Please note that if job goes above & beyond standard POA arrangement may apply instead.				
Tender process – distributor may carry out tender process on behalf of connection applicant or DNSP may assist connection application.	N/A	N/A	0.00	0.00	-
Protection and Power Quality assessment prior to connection - simple	Solar PV 30-150kW	Price Cap	3,791.55	3,791.55	-
Protection and Power Quality assessment prior to connection - complex	Solar PV 150kW+ and Non Solar PV 30kW+	Quoted Example Only	3,791.55	3,791.55	-
Application assessment, design review and audit real estate development (sub-division) connection services.	Design Assessment and Preparation of Offer Number of new, modified or recovered sites 7-30 Sites	Quoted Example Only (potentially price cap in the future)	1,055.87	1,055.87	-
Application assessment, design review and audit real estate (sub-division) connection services - resubmission	Design Assessment and Preparation of Offer - Resubmission	Price Cap	162.44	162.44	-
Site inspection in order to determine nature of connection	(small or large customer connection)	Price Cap	324.88	324.88	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Provision of site-specific connection information and advice for small or large customer connections.	Protection Devices & Settings, Fault level, Network Information	Price Cap	649.77	649.77	-
Preparation of preliminary designs and planning reports for small or large customer connection, including project scope and estimates	Large Customer Connection - Planning Report/Feasibility Report - Additional information provided by the Asset Management above and beyond NSC providing general connection enquiry services prior to the submission of an application for connection (requires engagement of Asset Management staff outside of the NSC)	Quoted Example Only	9,478.88	9,478.88	-
Customer build, own and operate consultation services.	N/A	N/A	0.00	0.00	-
Design & construct of connection assets for large customers.	Install new ground transformer substation to service commercial load. Substation includes installation of 2 x 1500KVA TX, safelink RMU, LB Board 300m of 11kv cable	Quoted Example Only	273,064.45	273,064.45	-
Commissioning and energisation of Large Customer Connection	Large Customer Connections	Quoted Example Only	8,390.23	8,390.23	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	assets to allow conveyance of electricity.				
Commissioning and energisation of connection assets for real estate development (sub-division)	Undertake High Voltage switching to allow developer to connect network they have constructed as part of the real estate development (sub-division), to the existing Energex network. Energex would enter the HV switching sheet into our system and arrange for resources to undertake the forward and reverse switching with the use of existing isolation switches in the network.	Quoted Example Only (potentially price cap in the future)	1,357.45	1,357.45	-
Augmenting the network to remove a constraint faced by an embedded generator	Removal of network constraint for a non-registered embedded generator - UPGRADE PMT TX 315 3 PH TO 500 3 PH SQ	Quoted Example Only	147,680.63	147,511.58	-0.1%
Review, Inspection and Auditing of design and works carried out by an alternative service provider prior to energisation.	Large Customer Connections - Design	Quoted Example Only	3,898.61	3,898.61	-
	Real estate development (sub-divisions)	N/A	0.00	0.00	-
Customer request a	Customer requested	Schedule 8	1,566.41	1,566.41	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
temporary connection for short term supply (includes metered and unmetered) - Simple	temporary Connection (Short Term) and recovery of the temporary builders supply (business hours) - No CT.				
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (business hours) - CT Metering. Includes additional crew.	Schedule 8	2,668.84	2,668.84	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (after hours) - No CT.	Price Cap	2,200.40	2,200.40	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (after hours) - No CT. Work requires traffic control due to imposed rules from external authorities.	Price Cap	3,259.28	3,259.28	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (after hours) - CT Metering. Includes	Price Cap	3,773.63	3,773.63	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	additional crew.				
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (after hours) - CT Metering. Work requires traffic control due to imposed rules from external authorities and additional crew.	Price Cap	4,832.51	4,832.51	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (any time) - No CT.	Price Cap	2,200.40	2,200.40	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (any time) - No CT. Work requires traffic control due to imposed rules from external authorities.	Price Cap	3,259.28	3,259.28	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (any time) - CT Metering. Includes additional crew.	Price Cap	3,773.63	3,773.63	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Customer requested temporary Connection (Short Term) and recovery of the temporary builders supply (any time) - CT Metering. Work requires traffic control due to imposed rules from external authorities and additional crew.	Price Cap	4,832.51	4,832.51	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Temporary Connection - Simple (Removal) after hours	Price Cap	0.00	0.00	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Temporary Connection - Simple (Removal) business hours	Price Cap	0.00	0.00	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Temporary Connection - Simple (Removal) anytime	Price Cap	0.00	0.00	-
Customer request a temporary connection for short term supply (includes metered and unmetered) - Simple	Temporary Connection of unmetered equipment to an existing LV supply	Price Cap	259.06	259.06	-
Customer requests a temporary	Provide temporary supply of 900 amps by	Quoted Example Only	105,105.22	105,105.22	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
connection for short term supply (includes metered and unmetered) - complex	extending 11kv network and installing 1000KVA padmount transformer				
Supply Abolishment - Simple	Request to de-energise an Unmetered Supply Point	Price Cap	397.77	397.77	-
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes. (business hours)	Price Cap	451.13	451.13	-
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes. (after hours)	Price Cap	524.51	524.51	-
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes. (after hours). Work requires traffic control due to imposed rules from external	Price Cap	1,583.39	1,583.39	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	authorities.				
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes. (any time)	Price Cap	524.51	524.51	-
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes. (any time) Work requires traffic control due to imposed rules from external authorities.	Price Cap	1,583.39	1,583.39	-
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community / unit one. (business hours)	Price Cap	294.77	294.77	-
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point	Price Cap	171.36	171.36	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	(simple). To be used for multi-unit residential complexes for all units after the community / unit one. (after hours)				
Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community / unit one. (anytime)	Price Cap	171.36	171.36	-
Supply Abolishment - Complex	To abolish LV supply that is fed directly from UG network to primary fuses on a commercial property.	Quoted Example Only	3,607.79	3,607.79	-
Move point of attachment.	N/A	N/A	0.00	0.00	-
Rearrange connection assets at customers request - complex	Pole to Pillar (installed by energex)	Quoted Example Only	9,609.61	9,609.61	-
Rearrange connection assets at customers request - complex	Overhead to Underground where existing main connection point does not exist ie have to install pillar. Includes cost of connection once pillar is installed	Quoted Example Only	8,721.55	8,665.20	-0.6%
Rearrange connection assets at customers request - simple (upgrade from overhead to underground where main	Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of	Price Cap	242.54	242.54	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
connection point is in existence)	existing overhead service to underground service (business hours).				
Rearrange connection assets at customers request - simple (upgrade from overhead to underground where main connection point is in existence)	Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (after hours).	Price Cap	346.11	346.11	-
Rearrange connection assets at customers request - simple (upgrade from overhead to underground where main connection point is in existence)	Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (any time).	Price Cap	346.11	346.11	-
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Single phase. (business hours)	Price Cap	615.66	615.66	-
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change	Price Cap	798.67	798.67	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	to load. Single phase. (after hours)				
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Single phase. (after hours) Work requires traffic control due to imposed rules from external authorities.	Price Cap	1,857.55	1,857.55	-
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Single phase. (any time)	Price Cap	798.67	798.67	-
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Single phase. (any time) Work requires traffic control due to imposed rules from external authorities.	Price Cap	1,857.55	1,857.55	-
Overhead Service Line Replacement at customers	Customer requests their existing overhead service	Price Cap	864.57	864.57	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
request (no material change to load)	to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Multi phase. (business hours)				
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Multi phase. (after hours)	Price Cap	1,095.62	1,095.62	-
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Multi phase. (after hours) Work requires traffic control due to imposed rules from external authorities.	Price Cap	2,154.50	2,154.50	-
Overhead Service Line Replacement at customers request (no material change to load)	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Multi phase. (any time)	Price Cap	1,095.62	1,095.62	-
Overhead Service Line Replacement at	Customer requests their existing	Price Cap	2,154.50	2,154.50	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
customers request (no material change to load)	overhead service to be replaced or relocated, e.g.as a result of Point of Attachment relocation. No material change to load. Multi phase. (any time) Work requires traffic control due to imposed rules from external authorities.				
Auditing services – auditing/re-inspection of connection assets after energisation to network - complex	Auditing / re-inspection of connection assets after energisation - Large Customer Connections	Quoted Example Only	1,357.45	1,357.45	-
Auditing services – auditing/re-inspection of connection assets after energisation to network - simple	Auditing / re-inspection of connection assets after energisation - real estate development (sub-division) Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits) 0-6	Price Cap	445.41	445.41	-
Auditing services – auditing/re-inspection of connection assets after energisation to network - simple	Auditing / re-inspection of connection assets after energisation - real estate development (sub-division) Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and	Price Cap	712.66	712.66	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	conduits) 7-30				
Auditing services – auditing/re-inspection of connection assets after energisation to network - simple	Auditing / re-inspection of connection assets after energisation - real estate development (sub-division) Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits) 31-60	Price Cap	852.65	852.65	-
Auditing services – auditing/re-inspection of connection assets after energisation to network - simple	Auditing / re-inspection of connection assets after energisation - real estate development (sub-division) Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits) 61+	Price Cap	950.21	950.21	-
Protection and Power Quality Assessment	embedded generation connected to network	Quoted Example Only	5,144.61	5,144.61	-
Customer requested works to allow customer or contractor to work close.	Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.	Quoted Example Not Provided	0.00	0.00	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Temporary disconnections and reconnections (which may involve a line drop) - Low Voltage	Temporary LV Service Disconnection/Reconnection - no dismantling (business hours)	Price Cap	347.88	347.88	-
Temporary disconnections and reconnections (which may involve a line drop) - Low Voltage	Temporary LV Service Disconnection/Reconnection - physical dismantling (business hours)	Price Cap	568.37	568.37	-
Temporary disconnections and reconnections (which may involve a line drop) - Low Voltage	Temporary LV Service Disconnection/Reconnection - no dismantling (after hours)	Price Cap	496.44	496.44	-
Temporary disconnections and reconnections (which may involve a line drop) - Low Voltage	Temporary LV Service Disconnection/Reconnection - physical dismantling (after hours)	Price Cap	811.09	811.09	-
Temporary disconnections and reconnections (which may involve a line drop) - Low Voltage	Temporary LV Service Disconnection/Reconnection - no dismantling (anytime)	Price Cap	496.44	496.44	-
Temporary disconnections and reconnections (which may involve a line drop) - Low Voltage	Temporary LV Service Disconnection/Reconnection - physical dismantling (anytime)	Price Cap	811.09	811.09	-
Temporary disconnections and reconnections (which may involve a line	HV - switching sheets for isolation	Quoted Example Only	1,175.94	1,175.94	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
drop) - High Voltage					
Customer initiated supply enhancement	Overhead Service Upgrade to Multiphase	Price Cap	1,145.40	1,145.40	-
Customer initiated supply enhancement	Overhead Service Upgrade to Multiphase (includes traffic control)	Price Cap	2,204.28	2,204.28	-
Customer initiated supply enhancement	Underground Service - Upgrade to multi phase	Price Cap	3,051.20	3,051.20	-
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 (eg reserve feeder). (1km of 11kV Feeder 240mm ² UG, and new conduits.)	Quoted Example Only	1,300,923.86	1,300,923.86	-
Customer consultation or appointment.	A visit to the customers premise to advise on electrical supply matters, could be for various reasons.	Price Cap	220.49	220.49	-
Rectification of Illegal Connections: Work undertaken as a consequence of illegal connections resulting in damage to the network	Rectification of illegal connections or damage to overhead or underground service cables	Quoted Example Not Provided	0.00	0.00	-
De-Energisation	Retailer requests de-energisation of the customer's premises where the de-	Price Cap	61.40	61.40	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	energisation can be performed at the premise ie. by a method other than Main Switch Seal (ie at Pillar Box, Pit or Pole Top). No CT.				
De-Energisation	Retailer requests de-energisation of the customer's premises where the de-energisation can be performed at the premise ie. by a method other than Main Switch Seal (ie at Pillar Box, Pit or Pole Top). CT Metering.	Price Cap	301.64	301.64	-
De-Energisation	Retailer requests de-energisation of the customer's premises where the customer has not paid their electricity account and the de-energisation can be performed at the premise ie. by a method other than Main Switch Seal (ie at Pillar Box, Pit or Pole Top). No CT.	Price Cap	61.40	61.40	-
De-Energisation	Retailer requests de-energisation of the customer's premises where the customer has not paid their electricity account and the de-energisation can be performed at the premise ie. by a method other than Main Switch Seal (ie at Pillar Box, Pit or Pole Top). CT	Price Cap	305.86	305.86	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	Metering.				
De-Energisation	De-energisation at the fuse or meter - Remove fuse NO CT business hours only	DNU	61.40	61.40	-
De-Energisation	De-energisation at the fuse or meter - Remove fuse CT business hours only	DNU	301.64	301.64	-
De-Energisation	De-energisation at the fuse or meter as part of a non-payment process - Remove fuse (non payment) NO CT business hours only	DNU	61.40	61.40	-
De-Energisation	De-energisation at the fuse or meter as part of a non-payment process - Remove fuse (non-payment) CT business hours only	DNU	305.86	305.86	-
De-Energisation	ENERGEX is requested by retailer to reconnect or disconnect a customer within a multiple premises - de-energisation requiring planned notification (> 10 customers)	Price Cap	0.00	0.00	-
De-Energisation	ENERGEX is requested by retailer to reconnect or disconnect a customer within a multiple premises - de-	Price Cap	0.00	0.00	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	energisation requiring planned notification (< 10 customers)				
De-Energisation	Retailer requests a de-energisation of the customer's premises and it is carried out by way of Main Switch Seal (non-payment).	Price Cap	20.12	20.12	-
De-Energisation	Retailer requests a de-energisation of the customer's premises and it is carried out by way of Main Switch Seal.	Price Cap	20.12	20.12	-
Re-Energisation	Retailer requests a re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (business hours).	Price Cap	46.90	46.90	-
Re-Energisation	Retailer requests a re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT Metering (business hours).	Price Cap	46.90	46.90	-
Re-Energisation	Retailer requests a re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (after hours).	Price Cap	66.51	66.51	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Re-Energisation	Retailer requests a re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT Metering (after hours).	Price Cap	66.51	66.51	-
Re-Energisation	Retailer requests a re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (any time).	Price Cap	66.51	66.51	-
Re-Energisation	Retailer requests a re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT Metering (any time).	Price Cap	66.51	66.51	-
Re-Energisation	Retailer requests that a meter reading be provided, with Energex to determine whether fieldwork is necessary to obtain reading.	Price Cap	0.00	0.00	-
Re-Energisation	Retailer requests that fieldwork be undertaken to obtain a new reading rather than using a deemed meter reading. May also be used for retrospective move-in requests.	Price Cap	9.57	9.57	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Re-Energisation	Retrospective move in read required	Price Cap	9.57	9.57	-
Re-Energisation	Retailer requests a re-energisation for the customer's premises following a main switch seal (no visual required) (business hours)	Price Cap	11.32	11.32	-
Re-Energisation	Retailer requests a re-energisation for the customer's premises following a main switch seal (no visual required) (after hours)	Price Cap	75.67	75.67	-
Re-Energisation	Retailer requests a re-energisation for the customer's premises following a main switch seal (no visual required) (any time)	Price Cap	68.56	68.56	-
Re-Energisation	Retailer requests a re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (business hours)	Price Cap	46.42	46.42	-
Re-Energisation	Retailer requests a re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (any time)	Price Cap	68.56	68.56	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Re-Energisation	Retailer requests a re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (after hours)	Price Cap	75.67	75.67	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days. - No CT (business hours)	Price Cap	107.76	107.76	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days. - CT Metering (business hours)	Price Cap	276.34	276.34	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days. - No CT (after hours)	Price Cap	153.56	153.56	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days. - CT Metering (after hours)	Price Cap	381.90	381.90	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days. - No CT (anytime)	Price Cap	153.20	153.20	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days. - CT Metering (anytime)	Price Cap	417.46	417.46	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises. No CT (business hours)	Price Cap	107.76	107.76	-
Re-Energisation	Retailer requests a visual examination	Price Cap	276.34	276.34	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	upon re-energisation of the customer's premises. CT Metering (business hours)				
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises. No CT (after hours)	Price Cap	153.56	153.56	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises. CT Metering (after hours)	Price Cap	381.90	381.90	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises. No CT (anytime)	Price Cap	153.20	153.20	-
Re-Energisation	Retailer requests a visual examination upon re-energisation of the customer's premises. CT Metering (anytime)	Price Cap	417.46	417.46	-
Attending Loss of Supply (customer at fault)	EGX attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) business hours.	Price Cap	220.49	220.49	-
Attending Loss of Supply	EGX attending LV customers	Price Cap	314.65	314.65	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
(customer at fault)	trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) anytime.				
Attending Loss of Supply (customer at fault)	EGX attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) after hours.	Price Cap	314.65	314.65	-
Accreditation of Design Consultants	DESKTOP MANGEMENT SYSTEM EVALUATION - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), Rate 2 public lighting, LCC & distribution works that are reticulated with Energex network (Design Accreditation) New applicant has ISO9001 accreditation with no other Energex accreditations in place	Price Cap	10,259.61	10,259.61	-
Accreditation of Design Consultants	DESKTOP MANGEMENT SYSTEM EVALUATION - Applicant requests to	Price Cap	11,956.42	11,956.42	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	<p>obtain Energex accreditation to provide design services for real estate development (sub-division), Rate 2 public lighting, LCC & distribution works that are reticulated with Energex network (Design Accreditation)</p> <p>New applicant is not ISO9001 accredited with no other Energex accreditations in place</p>				
Accreditation of Design Consultants	<p>DESKTOP MANGEMENT SYSTEM EVALUATION - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), Rate 2 public lighting, LCC & distribution works that are reticulated with Energex network (Design Accreditation)</p> <p>Applicant currently holds accreditation to undertake Design services for Rate 2 public lighting (Design Accreditation) Applicant requesting additional Energex accreditations with or without ISO9001</p>	Price Cap	7,010.77	7,010.77	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	accreditation (priced per additional accreditation).				
Accreditation of Design Consultants	<p>ONSITE MANAGEMENT SYSTEM EVALUATION (irrespective of prior accreditations)</p> <p>Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), Rate 2 public lighting, LCC & distribution works that are reticulated with Energex network (Design Accreditation)</p>	Price Cap	678.72	678.72	-
Accreditation of Design Consultants	<p>CAPABILITY EVALUATION (irrespective of prior accreditations)</p> <p>Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), Rate 2 public lighting, LCC & distribution works that are reticulated with Energex network (Design Accreditation)</p>	Price Cap	649.77	649.77	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Accreditation of Alternative Service Providers (Construction Accreditation)	<p>DESKTOP MANAGEMENT SYSTEM EVALUATION - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (Construction Accreditation)</p> <p>New applicant has ISO9001/AS4801/ISO14001 accreditation with no other Energex accreditations in place.</p>	Price Cap	5,003.56	5,003.56	-
Accreditation of Alternative Service Providers (Construction Accreditation)	<p>DESKTOP MANAGEMENT SYSTEM EVALUATION - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (Construction Accreditation)</p> <p>New applicant is not ISO9001/AS4801/ISO14001 accredited with no other Energex accreditations in place.</p>	Price Cap	9,386.30	9,386.30	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Accreditation of Alternative Service Providers (Construction Accreditation)	DESKTOP MANAGEMENT SYSTEM EVALUATION - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (Construction Accreditation)	Price Cap	5,003.56	5,003.56	-
	Applicant requesting additional Energex accreditations with or without ISO9001/AS4801/ISO14001 accreditation (price per additional accreditation).				
Accreditation of Alternative Service Providers (Construction Accreditation)	ONSITE MANAGEMENT SYSTEM EVALUATION (irrespective of prior accreditations) Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (Construction Accreditation)	Price Cap	1,357.45	1,357.45	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Accreditation of Alternative Service Providers (Construction Accreditation)	CAPABILITY EVALUATION (irrespective of prior accreditations) Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (Construction Accreditation)	Price Cap	1,328.49	1,328.49	-
Close out re-evaluation	QA and Capability process: This is to ensure the applicant has adequate QA documentation in place to satisfy Energex QA Advisor. Applicant will also be required to undertake a capability assessment to assess whether or not they meet Energex requirements.	Quoted Example Only	6,787.23	6,787.23	-
Management System Re-Evaluation	QA process: This is conducted on request from existing service providers and design consultants with the intent to improve their management system score.	Price Cap	6,787.23	6,787.23	-
Shared Assets Authority	High Level QA and capability process: This is conducted to ensure the	Price Cap	5,090.43	5,090.43	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	applicant has adequate Safety and QA documentation to meet Legislative and Energex WCS Requirements. Also involves a capability assessment of the applicant's ability to conduct the work.				
Certification of non-approved materials to be used on the network	Certification of non-approved materials to be used on the network - Simple	Quoted Example Only	2,923.95	2,923.95	-
Certification of non-approved materials to be used on the network	Certification of non-approved materials to be used on the network - Complex	Quoted Example Only	6,497.68	6,497.68	-
After Hours provision of meter exchange	After Hours exchange of meter – CT Metering (after hours - incremental costs only - base cost included in MSC)	Price Cap	344.52	344.52	-
After Hours provision of meter exchange	After Hours exchange of meter – No CT (after hours - incremental costs only - base cost included in MSC)	Price Cap	72.42	72.42	-
After Hours provision of meter exchange	After Hours exchange of meter – No CT (after hours - incremental costs only - base cost included in MSC)	Price Cap	51.30	51.30	-
After Hours installation of additional metering	After Hours Installation of additional Metering - CT	Price Cap	344.52	344.52	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	metering (after hours - incremental costs only - base cost included in MSC)				
After Hours installation of additional metering	After Hours Installation of additional Metering - PV CT metering (after hours - incremental costs only - base cost included in MSC)	Price Cap	183.27	183.27	-
After Hours installation of additional metering	After Hours Installation of additional Metering - single phase metering (after hours - incremental costs only - base cost included in MSC)	Price Cap	72.42	72.42	-
After Hours installation of additional metering	After Hours Installation of additional Metering - multiphase metering (after hours - incremental costs only - base cost included in MSC)	Price Cap	117.27	117.27	-
After Hours installation of additional metering	After Hours Installation of additional Metering - PV single phase metering (after hours - incremental costs only - base cost included in MSC)	Price Cap	61.53	61.53	-
After Hours installation of additional metering	After Hours Installation of additional Metering - PV multiphase metering (after hours -	Price Cap	76.34	76.34	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	incremental costs only - base cost included in MSC)				
After Hours removal of meter	After Hours Removal of Meter - No CT (after hours - incremental costs only - base cost included in MSC)	Price Cap	52.05	52.05	-
After Hours removal of meter	After Hours Removal of Meter - CT Metering (after hours - incremental costs only - base cost included in MSC)	Price Cap	166.00	166.00	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - CT metering - Overhead Connection	Price Cap	330.97	330.97	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - CT metering - P/Pole Connection	Price Cap	378.61	378.61	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - CT metering - Underground Connection	Price Cap	318.33	318.33	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - single phase metering - Overhead Fox Connection	Price Cap	131.67	131.67	-
After Hours provision of initial meter installation	After Hours Provision of initial meter	Price Cap	99.17	99.17	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	installation - single phase metering - Overhead Connection				
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - single phase metering - Underground Connection	Price Cap	75.37	75.37	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - multi phase metering - Overhead Fox Connection	Price Cap	166.61	166.61	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - multi phase metering - Overhead Connection	Price Cap	125.38	125.38	-
After Hours provision of initial meter installation	After Hours Provision of initial meter installation - multi phase metering - Underground Connection	Price Cap	97.79	97.79	-
Customer requested Meter Accuracy Testing of type 5-6 meter (physically test meter)	Testing for type 5 & 6 meters - customer requested meter accuracy testing - No CT	Schedule 8	365.40	365.40	-
Customer requested Meter Accuracy Testing of type 5-6 meter (physically test meter)	Testing for type 5 & 6 meters - customer requested meter accuracy testing - CT Metering	Schedule 8	761.91	761.91	-
Customer requested Meter Inspection & Investigation (no	Inspection required to check reported or suspected fault	Price Cap	89.74	89.74	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
physical testing of meter) no fault found	and no fault in meter is found. (no physical meter test) - No CT (business hours)				
Customer requested Meter Inspection & Investigation (no physical testing of meter) no fault found	Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT Metering (business hours)	Price Cap	333.57	333.57	-
Customer requested Meter Inspection & Investigation (no physical testing of meter) no fault found	Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - No CT (after hours)	Price Cap	161.91	161.91	-
Customer requested Meter Inspection & Investigation (no physical testing of meter) no fault found	Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - No CT (anytime)	Price Cap	161.91	161.91	-
Customer requested Meter Inspection & Investigation (no physical testing of meter) no fault found	Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT Metering (after hours)	Price Cap	476.02	476.02	-
Customer requested Meter Inspection & Investigation (no physical testing of meter) no fault found	Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT Metering (anytime)	Price Cap	476.02	476.02	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff (Controlled Load) - No CT	Price Cap	91.53	91.53	-
Customer requested meter reconfiguration	A request to make a change from Residential Flat (NTC 8400) to Residential ToU (NTC 8900) - No CT	Price Cap	139.64	139.64	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff (Controlled Load) - CT Metering	Price Cap	421.38	421.38	-
Customer requested meter reconfiguration	A request to make a change from Residential Flat (NTC 8400) to Residential ToU (NTC 8900) - CT Metering	Price Cap	465.47	465.47	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff - No CT (business hours)	Price Cap	91.53	91.53	-
Customer requested meter reconfiguration	A request to make a change from Residential ToU (NTC 8900) to Residential Flat (NTC 8400)	Price Cap	91.53	91.53	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff - CT Metering (business hours)	Price Cap	421.38	421.38	-
Customer requested meter reconfiguration	A request to make a change from Residential Flat (NTC 8400) or Residential ToU (NTC 8900) to PeakSmart ToU (NTC 7600)	Price Cap	139.64	139.64	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	- No CT				
Customer requested meter reconfiguration	Change Timeswitch - No CT	Price Cap	122.49	122.49	-
Customer requested meter reconfiguration	A request to make a change from Residential Flat (NTC 8400) or Residential ToU (NTC 8900) to PeakSmart ToU (NTC 7600) - CT Metering	Price Cap	450.78	450.78	-
Customer requested meter reconfiguration	Change Timeswitch - CT Metering.	Price Cap	387.08	387.08	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff - No CT (after hours)	Price Cap	108.18	108.18	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff - CT Metering (after hours)	Price Cap	601.32	601.32	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff - No CT (anytime)	Price Cap	108.18	108.18	-
Customer requested meter reconfiguration	A request to make a change from one tariff to another tariff - CT Metering (anytime)	Price Cap	601.32	601.32	-
Integrity verification as a result of a meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - No CT (business	Price Cap	128.00	128.00	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
metering equipment	hours)				
Integrity verification as a result of a meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT Metering (business hours)	Price Cap	793.15	793.15	-
Integrity verification as a result of a meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - No CT (after hours)	Price Cap	183.04	183.04	-
Integrity verification as a result of a meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT Metering (after hours)	Price Cap	1,131.87	1,131.87	-
Integrity verification as a result of a meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - No CT (anytime)	Price Cap	183.04	183.04	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
metering equipment					
Integrity verification as a result of a meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT Metering (anytime)	Price Cap	1,131.87	1,131.87	-
Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee.	Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee.	Quoted Example Not Provided	0.00	0.00	-
Check Read	Customer requests a check read on the meter due to reported error in the meter reading. This is only used to check the accuracy of the meter reading.	Price Cap	7.64	7.64	-
Final Read	Retailer requires a reading for preparing a final bill for customer.	Price Cap	7.64	7.64	-
Transfer Read	Customer requests a transfer read, as a result of transferring to a different retailer during a billing period.	Price Cap	7.64	7.64	-
Estimated Read	Estimated Read	Price Cap	10.61	7.72	-27.2%

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Type 5-7 non standard metering data services	A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (business hours) First Unit	Price Cap	127.90	127.90	-
Type 5-7 non standard metering data services	A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (business hours) Additional Units	Price Cap	64.20	64.20	-
Type 5-7 non standard metering data services	A request to conduct a site review of the state of the customer's metering installation(s) (no	Price Cap	365.02	365.02	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (after hours) First Unit				
Type 5-7 non standard metering data services	A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (after hours) Additional Units	Price Cap	183.23	183.23	-
Type 5-7 non standard metering data services	A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum	Price Cap	365.02	365.02	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (anytime) First Unit				
Type 5-7 non standard metering data services	A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (anytime) Additional Units	Price Cap	183.23	183.23	-
Type 5-7 non standard metering data services	Provision of load profile data where available – Retailer requested.	Quoted Example Only	146.99	146.99	-
Type 5-7 non standard metering data services	Provision of metering data above minimum regulatory requirements.	Quoted Example Not Provided	0.00	0.00	-
Type 5-7 non standard metering data services	Collection, processing and transfer of higher standard energy data for customers than would otherwise be provided – Retailer requested.	Quoted Example Not Provided	0.00	0.00	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
CT Metering	Provision, installation, testing and maintenance of instrument transformers for metering purposes	Price Cap	949.66	949.66	-
CT Metering	Testing and maintenance of instrument transformers for metering purposes	Price Cap	173.94	173.94	-
Metering Load Control	Install metering related load control	Quoted Example Not Provided	0.00	0.00	-
Metering Load Control	Remove local control relay or time clock	Quoted Example Not Provided	0.00	0.00	-
Metering Load Control	Change load control relay channel at retailer, customer or other third party request, that is not a part of initial load control installation, nor part of standard asset maintenance or replacement	Quoted Example Not Provided	0.00	0.00	-
Retailer of Last Resort (ROLR) event	Preparing lists of affected sites, and reconciling data with Australian Energy Market Operator listings; handling in-flight transfers; identifying open service orders raised by the failed retailer and determining actions to be taken in relation to those service orders; arranging estimate reads for the date of	Quoted Example Only	15,166.21	15,166.21	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	<p>the ROLR event and providing data for final NUOS bills in relation to affected customers; preparing final invoices for NUOS and miscellaneous charges for affected customers; preparing final debt statements; extracting customer data, providing it to the ROLR and handling subsequent enquiries; handling adjustments that arise from the use of estimate reads; assisting the retailer with the provision of network tariffs to be applied and the customer move in process; administration of any 'ROLR cost recovery scheme distributor payment determination'.</p> <p>This is an example cost of the insolvency of a retailer that of a size smaller than the big 3 (AGL)</p>				
Customer requests the provision of electricity network data requiring customised investigation analysis or technical input	Eg. Provision of accumulation data where available on request from retailer	Quoted Example Only	135.20	135.20	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
Customer requests the provision of electricity network data requiring customised investigation analysis or technical input	<p>Eg. Specific request for the provision of zone substation data (F&A P78 V13) The following are the basic requirements for delivery for the half hour data requests.</p> <p>Task Frequency Days Staff Initial Extraction via Script Once 5 Para professional Annual Update via Script Once per Year 2 Para professional Burn to Discs As Required 2 Para professional</p>	Quoted Example Only	162.44	162.44	-
Bundling (conversion) of cables carried out at the request of another party.	Eg. 1x40m span of open wire LV only replaced with LV bundled conductor. No pole replacement required.	Quoted Example Only	8,392.15	8,392.15	-
Provision of services to extend / augment the network, to make supply available for the connection of approved unmetered equipment, e.g. public telephones, streetlights, extension to the network to provide a point of supply for a billboard & city cycle.	Eg. Installation of a x street pole to supply connection for R3 streetlighting to Railway crossing	Quoted Example Only	5,109.44	5,010.83	-1.9%
Customer requested appointments.	Customer requested appointments.	Price Cap	220.49	220.49	-
Rearrangement of	Eg. Relocate LV	Quoted Example	11,484.65	11,484.65	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
network assets	inline pole with pin construction & concrete collar foundation	Only			
Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.	Eg Aerial Markers - Install & recover marker flags - 70 marker flags for 1 month	Quoted Example Only	2,058.06	2,058.06	-
Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.	Eg Tiger Tails	Quoted Example Not Provided	0.00	0.00	-
Assessment of parallel generator applications	Assessment of parallel generator applications	Quoted Example Not Provided	0.00	0.00	-
Witness Testing	Witness Testing	Quoted Example Only	3,033.24	3,033.24	-
Attendance at customers premises to perform a statutory right where access is prevented	Energex attends a site at the customers request and is unable to perform job due to customers fault. (business hours)	Price Cap	88.20	88.20	-
Attendance at customers premises to perform a statutory right where access is prevented	Energex attends a site at the customers request and is unable to perform job due to customers fault. (after hours)	Price Cap	125.86	125.86	-
Attendance at customers premises to	Energex (non technical) attends a site at	Price Cap	10.52	10.52	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
perform a statutory right where access is prevented	the customers request and is unable to perform job due to customers fault (business hours)				
Attendance at customers premises to perform a statutory right where access is prevented	Energex attends a site at the customers request and is unable to perform job due to customers fault (anytime)	Price Cap	125.86	125.86	-
Attendance at customers premises to perform a statutory right where access is prevented	Energex (non technical) attends a site at the customers request and is unable to perform job due to customers fault	Price Cap	75.38	75.38	-
Attendance at customers premises to perform a statutory right where access is prevented	Energex (non technical) attends a site at the customers request and is unable to perform job due to customers fault	Price Cap	75.38	75.38	-
Overhead Service Connection - non standard installation	Flying Fox (catenary) Overhead Connection difference between the cost of a standard OH service and the cost of a flying fox service.	Quoted Example Only	2,938.16	2,825.46	-3.8%
Overhead Service Connection - non standard installation	Flying Fox (catenary) Overhead Connection Existing Connection	Quoted Example Only	3,825.43	3,712.73	-2.9%
Provision of glare shields, vandal guards, luminaire replacement with	Replacement of existing streetlight luminaires with aero screen low	Price Cap	515.80	515.80	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
aero screens	glare luminaries				
Provision of glare shields, vandal guards, luminaire replacement with aero screens	Customer requests the supply and installation of adhesive luminaire glare screen(s).	Price Cap	187.50	187.50	-
Provision of glare shields, vandal guards, luminaire replacement with aero screens	Customer requests the supply and installation of standard luminaire glare screen(s) – internal.	Price Cap	153.26	153.26	-
Provision, of glare shields, vandal guards, luminaire replacement with areo screens	Provision of unique luminaries Supply and installation of custom external Glare screening	Quoted Example Only	2,168.90	2,168.90	-
Application assessment, design review and audit	Rate 2 Public Lighting services. Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits) 7-30 Sites	Quoted Example Only	1,055.87	1,055.87	-
Application assessment, design review and audit	Rate 3 Public Lighting services. Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street	Price Cap	81.22	81.22	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	light pits and conduits) 0-6 Sites				
	Rate 3 Public Lighting services.				
Application assessment, design review and audit	Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits) 7-30 Sites	Price Cap	121.83	121.83	-
	Rate 3 Public Lighting services.				
Application assessment, design review and audit	Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits) 31+ Sites	Price Cap	243.66	243.66	-
	Rate 2 Public Lighting services.				
Application assessment, design review and audit	Design Assessment and Preparation of Offer Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits)	Price Cap	162.44	162.44	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	Resubmission				
Construction of new street lighting services (contributed)	Construction of new street lighting services (contributed)	Quoted Example not provided	0.00	0.00	-
Alteration, repair, relocation, rearrangement or removal of existing street light assets and energy efficient retrofit.	Alteration, repair, relocation, rearrangement or removal of existing street light assets and energy efficient retrofit.	Quoted Example not provided	0.00	0.00	-
A fee for the residual asset value of non-contributed public lights when removed from service before the end of their useful life at the request of the customer.	A fee for the residual asset value of non-contributed public lights when removed from service before the end of their useful life at the request of the customer.	Quoted Example not provided	0.00	0.00	-
New public lighting technologies, including trials	Trial of new public lighting technologies for consideration of standard product - Fixed costs associated with Trial Establishment and Administration. (Note: Costs per luminaire selected for trial are detailed separately below)	Quoted Example Only	341,418.70	341,418.70	-
New public lighting technologies, including trials	Trial of new public lighting technologies for consideration of standard product - Costs per luminaire selected for trial. (Note: Typically	Quoted Example Only	19,767.33	19,767.33	-

Service Category	Service Description	Fee Type	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	% (preliminary cf proposed)
	at least 100 luminaires are minimum number for a trial.)				
Energy efficient retrofit (including where customer requests to retrofit existing assets before end of life)	Replace 1 x 50w Mercury Vapour luminaire with energy efficiency retrofit 32CFL	Quoted Example Only	349.28	349.28	-

Labour Category	AER preliminary decision on maximum labour charge rates for quoted services, (\$2014–15)
Apprentices	N/A
Power Workers	Confidential
Administration/ Clerical	Confidential
Customer Connections Labour Rate	N/A
Electrical System Design Advisors	Confidential
Technical/ Service Persons	Confidential
Para professional	Confidential
Supervisors	Confidential
Professional Managerial	Confidential
System Operators	N/A
Senior Professional	N/A

Source: AER analysis.

A.2 Metering

Table 16.24 Annual metering charge – Preliminary decision (\$ nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19	2019–20
Primary	Non–capital	10.81	10.65	10.49	10.33	10.18
	Capital	24.48	24.12	23.76	23.40	23.05
Load control	Non–capital	3.24	3.19	3.15	3.10	3.05
	Capital	7.34	7.23	7.13	7.02	6.92
Solar PV	Non–capital	7.56	7.45	7.34	7.23	7.12
	Capital	17.14	16.88	16.63	16.38	16.14

Source: AER analysis

Note: Prices for 2016–17 to 2019–20 are indicative only and will be adjusted for actual CPI during the AER's annual pricing approval processes.

Table 16.25 AER preliminary decision X factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	3.94	3.94	3.94	3.94

Source: AER analysis

Table 16.26 Upfront capital charge – Preliminary decision

Meter	Upfront capital charge (\$2014–15)
DC 1 Element Single Phase	297.84
DC 2 Element Single Phase	388.25
DC Polyphase	581.27
CT Polyphase	1639.27

Source: AER analysis

Table 16.27 AER preliminary decision X factors for upfront charge (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	-0.22	-0.44	-0.43	-0.46

Source: AER analysis.

Note: To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as defacto X factors. Therefore, they are negative