



PRELIMINARY DECISION
Ergon Energy 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 Ergon Energy'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 Ergon Energy's proposed fees for ancillary network services. For these services, Ergon Energy's proposed charges 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 Ergon Energy can charge for ancillary network services for the first year of the 2015–20 regulatory control period.

Table 16.20 sets out charges for fee based services and Table 16.21 sets out charges and labour rates for 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 form of control to ancillary network services.³ 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.⁴

Form of control—fee based services

Our preliminary decision is to apply a price cap for the form of control to fee based services.⁵ 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 16.20.

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.

³ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 67.

⁴ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 65; Ergon Energy, *Regulatory proposal 2015-20*, 31 October 2014, p. 46.

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

Note: To be clear, the 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.

A_t^{\dagger} 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

Our preliminary decision is to apply a formula to determine the cost build-up of services that are priced on a 'quoted' basis.⁶

Figure 16.2 Quoted services formula

$$Price = Labour + Contractor Services + Materials + Capital Allowance$$

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 $(1-X_t)(1+\Delta CPI_t)$.⁷

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 Ergon Energy's proposal

Ergon Energy proposes to use the cost build-up formula (in Figure 16.2) to establish initial prices (or base prices) for fixed fee services in the first year of the 2015–20 regulatory control period.⁸

Ergon Energy assumed the price caps will operate in the following way for fixed fee services:

⁶ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, pp. 67–68.

⁷ The definition of X and ΔCPI for Figure 16.2 are the same as for Figure 16.1.

⁸ Ergon Energy, *Regulatory proposal 2015-20*, 31 October 2014, p. 46.

- The initial price (or base price) will be set for each service in the first year of the regulatory control period.
- From year two onwards of the regulatory control period, services will be subject to the price caps using the controls provided in the price cap formula in Figure 16.1.
- The price cap formula allows prices to be annually adjusted for:
 - inflation (CPI)
 - real cost escalation (X-factor)
 - other adjustments allowed to be passed through in capped prices (Adjustment factor).

The result of the above essentially limits the annual movement in prices to an annual adjustment or escalation. This is primarily driven by changes in CPI and other changes to underlying cost drivers for different services (X-factor).⁹

16.1.3 Assessment approach

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

- Ergon Energy's regulatory proposal.¹⁰
- Maximum total labour rates we developed for Queensland. We based our findings on our consultant, Marsden Jacob's, analysis for our NSW draft decision.¹¹
- We consider labour is the key input in determining an efficient level of fees for ancillary network services. We focused on comparing Ergon Energy'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

⁹ Ergon Energy, *Regulatory proposal 2015-20*, 31 October 2014, p. 47.

¹⁰ Ergon Energy, *Regulatory proposal 2015-20*, 31 October 2014, pp. 45-62; Ergon Energy, *Regulatory proposal 2015-20—05.05.01: Inputs and assumptions for alternative control services*, 31 October 2014, pp. 1-36.

¹¹ Marsden Jacob Associates, *Final provision of advice in relation to alternative control services—public version*, 20 October 2014.

appropriate fees for services will provide Ergon Energy with a reasonable opportunity to recover at least the efficient costs it incurs in providing these services. It will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services.¹²

Where Ergon Energy'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 for ancillary network service charges. Equally, we applied Ergon Energy'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 Ergon Energy'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.¹³

16.1.4 Reasons for preliminary decision

We do not approve Ergon Energy's proposed fees for ancillary network services. Proposed fees exceed those based on maximum total labour rates (which we consider efficient) for Ergon Energy's labour types for providing these services. As we set out in section 16.1.3, we compared Ergon Energy'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 Ergon Energy's revenue. This is because a relatively small number of Ergon Energy'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 Ergon Energy should pay for the various labour types. Where Ergon Energy 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.

We carefully assessed Ergon Energy's proposed fees for Ancillary Services to ensure they are prudent. Our assessment focused on the inputs to the methods the distributor Ergon Energy used to derive its fees for ancillary network services. In particular, labour is the major input to Ergon Energy'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 Ergon Energy's total labour rates where they exceeded the maximum total labour rates that we developed (see section 16.1.4). Specifically, we

¹² NEL, s7A and 16

¹³ Deloitte Access Economics, *NSW distribution network service providers labour analysis—Addendum to 2014 report*, April 2015.

adjusted the labour rate Ergon Energy 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 Ergon Energy 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.

Table 16.2 shows the maximum total labour rates we developed for each of Ergon Energy's labour types. We consider these maximum total labour rates should be used to assess Ergon Energy'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 Ergon Energy'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.

Table 16.2 Maximum allowed total labour rates

Labour Category	AER maximum total labour rates (\$2014–15)
Apprentice	N/A
Trainee	N/A
Power Worker	125.07
Admin Employee	73.90
Technical Service Person	181.92

Labour Category	AER maximum total labour rates (\$2014–15)
Electrical System Designer	170.55
Supervisor	181.92
Para-Professional	181.92
System Operator	N/A
Professional Managerial	170.55
Manager	N/A

Source: AER analysis.

Note: Ergon Energy 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.¹⁴ 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.¹⁵ We compared the 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.

¹⁴ 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.

¹⁵ Marsden Jacob Associates, *MJA analysis*.

To calculate the maximum raw labour rates, we used job titles from Hays' energy specific salary guide.¹⁶ We supplemented this with data from the Hays office support salary guide.¹⁷ 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)
	Project coordinator
Technical specialist	Technician
	Control room operator
	Control room manager
	E&I technician
	Protection technician
	Generator technician
	Operator / manager
	Site engineer
	Planner / scheduler
	OHS supervisor

¹⁶ Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

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

Labour category	Job title
	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 jointer
	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 Ergon Energy 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
Apprentice	N/A
Trainee	N/A
Power Worker	52.88
Admin Employee	31.25
Technical Service Person	76.92
Electrical System Designer	72.12
Supervisor	76.92
Para-Professional	76.92
System Operator	N/A
Professional Managerial	72.12
Manager	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 Ergon Energy's Enterprise Agreement and the Queensland State Payroll Tax.¹⁸ 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	Ergon Energy'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	43.5

Source: AER analysis.

16.1.4.3 Overheads

We have 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.¹⁹ In recommending 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.²⁰ Marsden Jacob therefore recommended an

¹⁸ Ergon Energy, *Ergon Energy Union Collective Agreement 2011*, pp. 70-92.

¹⁹ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

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.

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.²¹ 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.²²

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.²³ 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.²⁴ By extension, proper application of the cost allocation method does not indicate whether the resulting overhead rates represent efficient levels.

16.2 Metering

Our preliminary decision on Ergon Energy's metering proposal is made in the context of ongoing policy reform. We based our assessment on the National Electricity Rules

²¹ 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).

²² Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

²³ AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

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

(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.²⁵

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'.²⁶ 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.²⁷

Our preliminary decision takes the AEMC's draft rule into account and establishes a regulatory framework for the 2015-20 regulatory period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.²⁸ This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

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.

²⁵ 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).

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

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

²⁸ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 79.

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.²⁹ We further maintain that the control mechanism for alternative control services will be caps on the prices of individual services.³⁰

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:

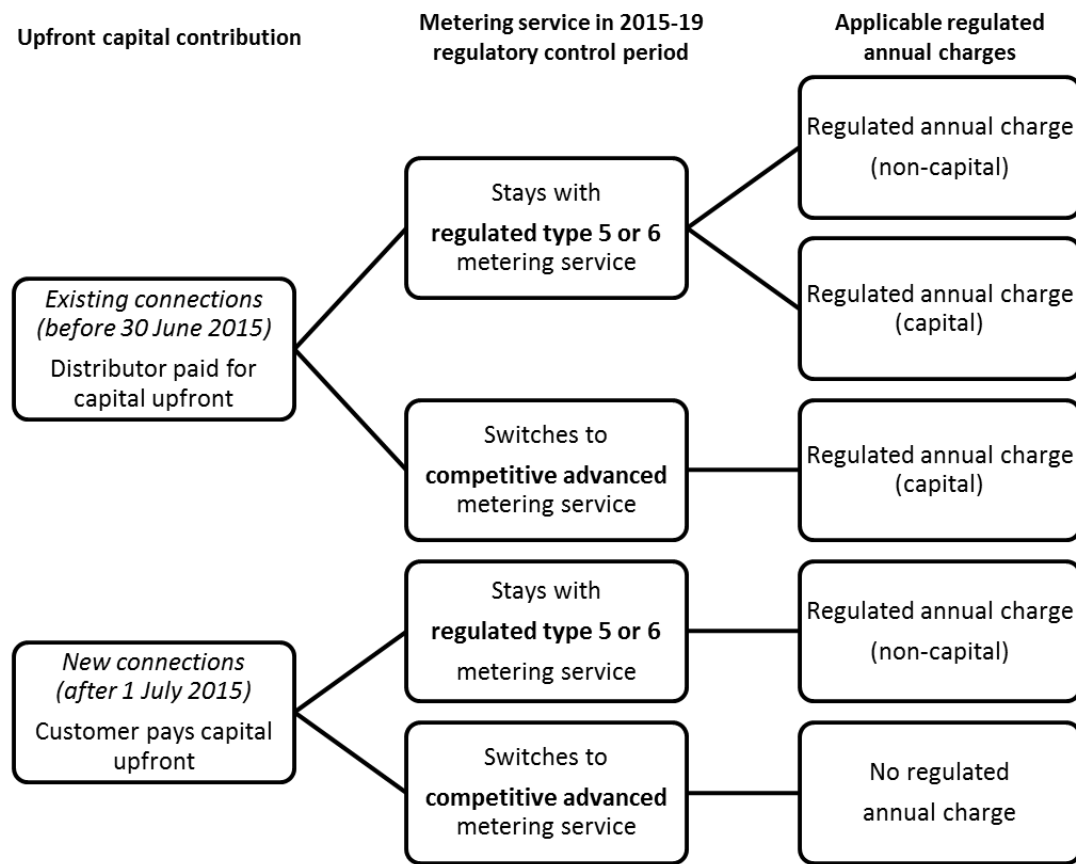
- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising of two components:
 - capital —metering asset base (MAB) recovery
 - non-capital—operating expenditure and tax.

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

²⁹ AER, *Final framework and approach for Energex and Ergon Energy*, April 2014. p. 21

³⁰ 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.

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 recovery³¹) component of regulated annual metering charge
- Non-capital (opex and tax) component of the regulated annual metering charge.

³¹ 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 Ergon Energy's building block approach as the basis for establishing annual metering charges but not the particular components:

- Opening metering asset base
- Our preliminary decision is to approve an opening metering asset base (MAB) value as at 1 July 2015 of \$60.7 million and substitute it with Ergon Energy's proposed \$61.6 million.
- Depreciation
- Our preliminary decision accepts a standard asset lives of 15 years. This is instead of Ergon Energy's proposal to apply accelerated depreciation of 3 years for newly installed meters and 5 years for pre-existing metering assets.³²
- We will apply forecast depreciation, consistent with our preliminary decision for standard control services.
- Forecast capex
- We do not accept Ergon Energy's proposed capex building block. Our preliminary decision allows \$51.3 million in capex for annual metering charges instead of Ergon Energy's proposed \$129.1 million (\$2014-15). Of the capex we have not accepted, approximately 71 percent relates to our preliminary decision to move the cost recovery of new connections from the annual metering charge to upfront payments. That is, Ergon Energy 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 cost assessment led us to accept \$118.6 million in opex for annual metering charges and substitute that amount for the proposed \$169.5 million (\$2014-15).

16.2.1.3 Upfront capital charges

Ergon Energy did not propose any upfront capital charges. We, however, consider their introduction to be economically efficient, with respect to new or upgraded connections. We have therefore included them in the structure of metering charges which we have accepted in this preliminary decision.

16.2.1.4 Metering exit fee

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

³² Ergon Energy, Regulatory proposal, November 2014, p. 48.

We do not approve Ergon Energy'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	-2.76	-2.76	-2.76	-2.76

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.

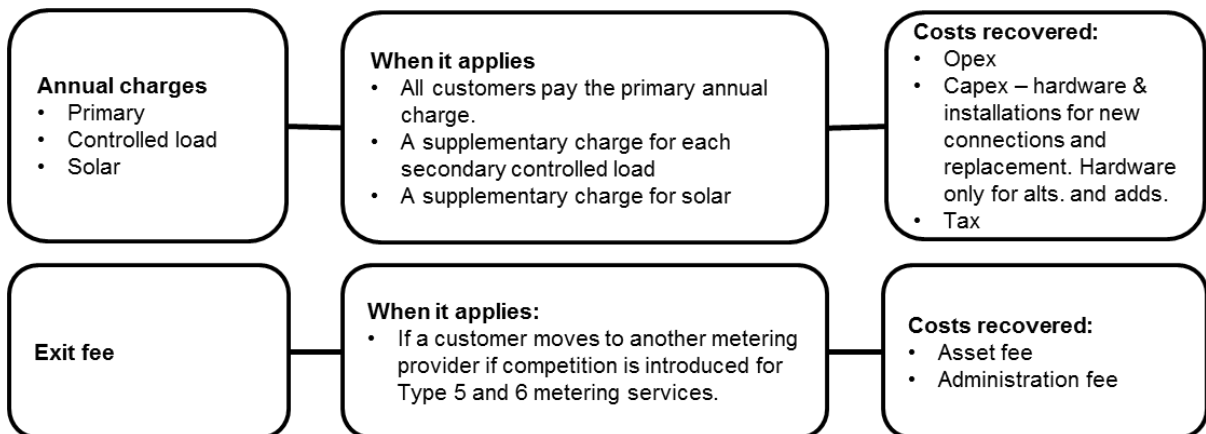
We will check for compliance with the control mechanism during the annual pricing process. To be compliant, Ergon Energy must annually adjust individual price caps in accordance with the control mechanism formula shown above. Further, Ergon Energy must show that individual prices are less than or equal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

16.2.2 Ergon Energy's proposal

16.2.2.1 Structure of metering charges

Ergon Energy 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. Figure 16.4 sets out the two types of metering services proposed by Ergon Energy. These are an annual metering service charge and an exit fee.

Figure 16.4 Proposed Metering Structure



16.2.2.2 Annual metering services

Ergon Energy proposed three annual metering service charges, a primary metering tariff and two secondary metering tariffs for controlled load and solar PV customers. Table 16.83 sets out Ergon Energy'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	85.31	83.56	81.87	80.23	78.66
Controlled load	31.37	30.72	30.10	29.50	28.92

Solar	21.21	20.78	20.36	19.95	19.56
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Source: Ergon Energy, 2015-20 Regulatory Proposal, p 51, table 26.

Ergon Energy 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	4.9	6.1	6.8	6.8	5.9
Return of capital	11.1	19.9	29.8	40.7	42.6
Opex	32.8	34.4	36.9	39.0	40.6
Tax allowance	3.1	5.6	8.2	11.0	11.1
Proposed annual revenue requirement	51.9	66.0	81.7	97.5	100.1

SOURCE: Ergon Energy, 2015-20 Regulatory Proposal, p 50, table 24.

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. Ergon Energy proposed an opening MAB value of \$61.6 million.

Ergon Energy proposed accelerated 5 year depreciation of the opening MAB. It also proposed to expense all meters installed in the 2015-20 regulatory period (new connections, replacements, alterations and additions) over a period of 3 years which will avoid adding forecast capex to the MAB.

The proposed forecast capex includes hardware capital costs associated with new connections, replacement, alterations and additions. It further includes the installation capital costs for new connections and replacement meters. However, with respect to the installation costs for alterations and additions, Ergon Energy proposed to charge customers upfront. This is as an ACS quoted service.

Ergon Energy's proposed capex of \$128.9 million (\$2014-15) for the 2015-20 regulatory period. This is a 47 percent real increase in metering capex compared to the

current regulatory period. This is entirely driven by an increase in the planned meter replacement program.

Forecast opex was developed using base-step-trend methodology. Ergon Energy used revealed costs from a single year, 2012-13, as the base. It proposed a \$1 million (\$2014-15) step increase for preventative maintenance to meet AEMO requirements.

Ergon Energy forecast 2 per cent annual growth in new connections. It forecasts alterations and additions due to solar to decrease compared with the current regulatory control period.

16.2.2.3 Metering exit fee

Ergon Energy have proposed a single exit fee that will apply if a customer chooses to move to another metering provider if competition is introduced for type 5 and 6 metering services.

Table 16.10 - Proposed exit fee

\$ nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Exit admin fee	50.53	53.10	57.21	60.66	63.44
Exit asset fee	86.44	102.69	108.50	103.34	85.68
Total exit fee	136.97	155.78	165.71	164.00	149.13

Source: Ergon Energy, 2015-20 Regulatory Proposal, p 51, table 26

The administration fee is based on the labour cost of taking 35 minutes of an administration employee's time to process a customer transfer in Ergon Energy's systems.

The asset fee is the average residual value of the forecast MAB divided by forecast primary metering tariff numbers in the relevant year.

16.2.3 AER's assessment approach

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

16.2.3.1 Structure of metering services

We considered Ergon Energy proposed structure of metering services and whether it complies with our Framework and Approach.

Our Framework and Approach, published in April 2014, sets out our proposed service classification and control mechanism for Ergon Energy's distribution services in the

2015–20 regulatory control period. In that way, it establishes a structure of metering services for which Ergon Energy's regulatory proposal should comply.

For type 5 and 6 metering services, our Framework and Approach specified an alternative control service classification.³³ It also stated that the control mechanism would be a cap on the price of individual services.³⁴ In making our assessment of Ergon Energy'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.³⁵

We also considered requirements in the NER. In particular, the service classification and control mechanism factors.³⁶ 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).

³³ AER, *Final framework for Energex and Ergon Energy*, April 2014, p. 52.

³⁴ AER, *Final framework for Energex and Ergon Energy*, April 2014, p. 45.

³⁵ AEMC, *Draft Rule Determination (Expanding competition in metering and related services)*, 26 March 2015, p 225

³⁶ 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.³⁷

16.2.3.2 Annual metering services

We assessed Ergon Energy's proposed opening MAB, depreciation, forecast capex and forecast opex 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 Ergon Energy 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 Ergon Energy 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 Ergon Energy's 'unit costs' and 'volume forecasts'. More specifically, we assessed the proposed:

- 'material' and 'non-material' unit costs
- 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 operating expenditure, we used a top-down 'base, step and trend' approach which we explain further below.

16.2.3.2.4.1 Base

As operating expenditure is largely recurrent in nature, we considered Ergon Energy's historical costs to be a useful starting point to establish a base to forecast future costs.

³⁷ NEL, Revenue and Pricing Principles, 7A (2).

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.³⁸

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.

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 distributors 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.

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.³⁹ Our assessment approach is consistent with our *Expenditure forecast assessment guideline*.⁴⁰

³⁸ AER, Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample, November 2013.

³⁹ NER, clause 6.5.6(c).

⁴⁰ AER, *Expenditure assessment forecast guideline*, November 2013, p.11, 24.

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.⁴¹ 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.⁴²

16.2.3.3 Upfront capital charge

Ergon Energy did not propose any upfront capital charges. We nonetheless provided the distributor with an opportunity to comment on how such charges should be calculated.⁴³ Our preliminary decision took those comments into account, along with a report we received from Marsden Jacob. This report recommended the maximum material and non-material unit costs we should accept.

16.2.3.4 Metering exit fee

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

⁴¹ NER, cl. 6.5.6 and 6.5.7.

⁴² NER, cl. 6.5.6(c) and 6.5.7(c).

⁴³ Ergon Energy, AER Ergon Energy 043, Email dated: 16 April 2015.

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.⁴⁴

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 Ergon Energy's with an opportunity to recover at least its efficient costs.⁴⁵ 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 Ergon Energy'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,⁴⁶ 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 changes for price caps for alternative control services will be consistent with our price control mechanism formula set out in 0.

16.2.5 Reasons for preliminary decision

Our reasons for not accepting Ergon Energy'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 Ergon Energy's proposed structure of metering services.

⁴⁴ Australian Energy Market Commission, Draft rule determination, Expanding competition in metering and related services, 26 March 2015.

⁴⁵ NEL, Revenue and Pricing Principles, 7A (2).

⁴⁶ Direct control services include standard and alternative control 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.⁴⁷

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.*"⁴⁸ 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.

Ergon Energy 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.⁴⁹ 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.⁵⁰ Therefore, the first mover competitive metering provider may have to pay for both an 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 stakeholders⁵¹, we decided on a method that we considered best balances the

⁴⁷ 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.

⁴⁸ QCOSS Submission to AER Consultation Paper (Recovery of Residual Metering Costs), 31 March 2015, p 2

⁴⁹ 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.

⁵⁰ Vector Limited, Submission on DNSPs regulatory proposals, 8 August 2014 p. 4.

⁵¹ 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

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 Ergon Energy'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
 - 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 Ergon Energy has, rather than relying on further information on the remaining

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.

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.⁵² 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 2017⁵³
 - 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

⁵² 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 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.

⁵³ AEMC, Expanding competition in metering and related services, Draft Rule Determination, 26 March 2015, p. 79.

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 Ergon Energy's total proposed building block requirement for annual metering services. We accept a building block approach to setting charges but not the following components of Ergon Energy's proposal:

- capex
- opex
- opening metering RAB.

This has led us to reject Ergon Energy'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 \$60.7 million compared to Ergon Energy's proposed \$61.6 million (\$nominal).

To calculate the opening MAB, we reclassified metering assets from standard to alternative control services. This is consistent with our F&A service classification.⁵⁴ Ergon Energy's proposal also moved meters from its standard control services RAB. However, to correct an error in the remaining asset lives, we have made a small change to the amount moved over to the opening MAB value. For more information, see attachment 2.

16.2.5.2.2 Depreciation

Our preliminary decision accepts a standard asset lives of 15 years. This is instead of Ergon Energy's proposal to apply accelerated depreciation of 3 years for newly installed meters and 5 years for pre-existing metering assets.⁵⁵

In support of its proposal for accelerated depreciation, Ergon Energy stated that its approach would assist in minimising the risk of stranded assets following the opening up of competition in metering.⁵⁶ We do not, however, accept that this risk is significant enough to warrant the proposed asset lives. The Queensland Council of Social Services shared this position, noting that Ergon Energy proposed 15 year for its assets. It continued:

While QCOSS recognises that smart meters may render existing accumulation meters obsolete prior to the end of their standard life, QCOSS considers Ergon Energy's approach [to depreciation] much more reasonable. Furthermore,

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

⁵⁵ Ergon Energy, Regulatory proposal, November 2014, p. 48.

⁵⁶ Ergon Energy, Regulatory proposal, November 2014, p. 48.

competition in metering services is likely to emerge in Southeast Queensland [Energex's distribution area] at a faster rate than in regional Queensland [Ergon Energy's distribution area].⁵⁷

We agree with QCOSS' submission. For both newly installed and pre-existing meters, we have substituted Ergon Energy's proposed standard asset life proposal with 15 years. We have selected 15 years because this is the expected technical lifetime of the meters. We also have corrected a minor error in Ergon Energy's proposal, leading to a small change in the remaining asset lives of its metering assets. For more information about that adjustment, see attachment 2.

We confirm that forecast, as opposed to actual, depreciation will apply to determining Ergon Energy'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 \$51.3 million in capex for annual metering services compared to Ergon Energy's proposed \$129.1 million (2014–15).

When considering direct costs only, most of the capex we have not approved in our preliminary decision (71 percent or \$35.7 million) relates to moving the cost recovery of two services within 'customer initiated works' category.⁵⁸ These are new connections and metering alterations and additions. Our preliminary decision moves the cost recovery of these services from the annual metering charge to upfront payments, made by customers directly to Ergon Energy. As such, Ergon Energy should still recover its costs associated with these customer initiated works; however, this will occur via a different capitalisation policy.

Table 16.12 sets out Ergon Energy's proposed capex and our preliminary decision on each cost category. The adjustment we made to Ergon Energy's indirect costs (overheads) was made in proportion to our substitute for direct costs. It therefore reflects our reallocation of some costs associated with customer initiated works, from the annual metering charge to upfront payments.

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

	2010–15	Proposed	Unit cost adjustment	Volume adjustment	Preliminary decision
New connections	14.7	16.6	0.0	16.6	0.0
Alterations and additions	29.7	19.1	0.0	19.1	0.0

⁵⁷ QCOSS, Submission on QLD regulatory proposals 2015–20, January 2015, p. 89.

⁵⁸ When indirect costs are included, the reallocation of the direct costs associated with new connections and metering alterations and additions is equal to about 43 percent of the expenditure we have not approved.

	2010–15	Proposed	Unit cost adjustment	Volume adjustment	Preliminary decision
Corrective maintenance	7.7	7.8	0.0	0.0	7.8
Customer initiated works		43.5	0.0	35.7	7.8
Replacement	3.9	36.5	0.0	14.4	22.1
Other system	0.0	2.7	0.0	0.0	2.7
Total direct costs	56.0	82.7	0.0	50.1	32.6
Overheads	0.0	46.4	0.0	28.1	18.3
Total	56.0	129.1	0.0	78.2	51.3

16.2.5.2.4 Unit costs

16.2.5.2.4.1 Material unit costs

We accept Ergon Energy's proposed material unit costs. In reaching this preliminary decision, we took into account the jurisdictional requirements for which Ergon Energy 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 Ergon Energy must install type 5 interval meters. These meters must be upgradable for use in a type 4 smart metering installation.⁵⁹ Until upgraded, the interval meters are read by Ergon Energy on a type 6 accumulation basis.

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

- When disregarding whether it is prudent or not to install interval meters, we conclude that Ergon Energy's proposed material unit costs should be accepted. Ergon Energy's proposed material unit costs were forecast using an average replacement cost in 2012–13. In that regard, it did not propose unit costs for single, dual and three phase meters, like other businesses have in their regulatory proposals, such as Energex.⁶⁰ It instead trended forward an historical average.
- We assessed Ergon Energy's historical average to be efficient. Specifically, we assessed Ergon Energy's proposed average material unit costs as lower than the weighted average material unit cost Energex put forward in its regulatory proposal. Since we assessed Energex's proposed material unit costs for single, dual and three phase meters to be within our observed market ranges,⁶¹ we have come to

⁵⁹ AEMO, Metrology Procedure: Part A National Electricity Market, v3.20.

⁶⁰ Energex, Regulatory proposal, Model 9: Metering indicative prices for 2015–20, November 2014.

⁶¹ AER, *Preliminary decision: Energex's regulatory proposal for 2015–20*, April 2015, p. 42.

the same conclusion for Ergon Energy. Therefore our preliminary decision is to make no adjustments to the proposed capex for material unit costs.

16.2.5.2.4.2 Non-material cost

In assessing Ergon Energy'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 Ergon Energy's proposed non-material unit costs. The amount 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.

16.2.5.2.5 Forecast volumes

We do not accept Ergon Energy's forecast volume of customer initiated connections. This is because our preliminary decision applies a different capitalisation policy to Ergon Energy's proposal. We also substitute Ergon Energy's proposed volume forecast for replacements. Table 16.13 sets out Ergon Energy's forecasts against our preliminary decision.

Table 16.13 Forecast and approved volumes of meter replacements

	Forecast	Preliminary decision
Customer initiated works		
New connection meters	78 353	0
Alterations and additions	125 375	0
Corrective maintenance	49 250	49 250
Replacements	124 720	65 669

Source: Ergon Energy, Regulatory proposal, Attachment 05.03.01, p. 17.

16.2.5.2.5.1 New connections

We do not accept any forecast volumes associated with new connections. Consistent with previous AER decisions,⁶² we consider there to be substantial benefits if Ergon

⁶² 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*

Energy changes its capitalisation policy. This is so that the costs of installing meters at new 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. When implemented, our approach to Ergon Energy's capitalisation policy for new connections (upfront payments) should help level the competitive playing field for new meters. This is by shifting how Ergon Energy'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, Ergon Energy will still be able to recover its costs. The only difference between our preliminary decision and Ergon Energy's proposal 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 new connections and metering additions and alterations. The upfront charges our preliminary decision accepts for these customer initiated works are set out in Appendix A.

16.2.5.2.5.2 Replacements

Our preliminary decision is to not accept Ergon Energy's proposed volume forecast for meter replacements. We substitute Ergon Energy's proposed 108 450 replacements with 65 669, which we consider to be more reflective of the business' compliance obligations in the 2015–20 regulatory control period.

Ergon Energy's proposed replacement program is informed by regulatory obligations under the NER and Australian Standard 1284.13.⁶³ Together these regulatory instruments create requirements on Ergon Energy 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.⁶⁴ For type 6 meters it is +/-2.0 percent.⁶⁵ 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

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.

⁶³ AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 2–3.

⁶⁴ NER, S7.2.3.1.

⁶⁵ NER, S7.2.3.1.

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.

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.⁶⁶ 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. Where we consider that threshold for replacement to be passed, we accept Ergon Energy is under a regulatory obligation to replace a family of meters, consisting of a particular make and model.

We nonetheless consider Ergon Energy's forecast volume of replacements to be overstated. Table 16.14 sets out the components of Ergon Energy's forecast and our assessment. Specifically, our preliminary decision does not accept 42 781 meter replacements with the description 'Warburton Franki type WF2' and a further 1 000 called 'Ferranti Type TM2c'. It does, however, accept the balance of the remaining proposed meter replacements (64 519).

Table 16.14 Proposed and approved replacement volumes

Description	Reason for replacement	Forecast volume	Approved volume
EMMCO type BAZ meters	Non-compliant	61 219	61 219
Warburton Franki type WF2	End of life	42 781	0
Ferranti Type TM2c	End of life	1 000	0
EMMCO type MC, AS and HMT	Unidentified non-compliant meters	150	150
Enernet K410/Tk410	Failing component	2 000	2 000
Nilsen EMS 2100	Failing displace	1 300	1 300
Total		108 450	64 519

Source: AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 1–2.

Our preliminary decision accepts that the replacement of 61 219 meters with the 'EMMCO type BAZ' description need to be replaced. This is because these meters belong to a family which has failed accuracy limits set out in Australian Standard

⁶⁶ NER, cl. 7.6.2.

1284.13 and Chapter 7 of the NER. We also accept that a small amount of meters which have already failed sample testing may be identified from time to time. Our preliminary decision accordingly accepts a further 150 unidentified non-compliant meters, together with the replacement of a total of 3 300 meters which have failing components.

We do not accept the replacement of the Warburton Franki meter family because the results of Ergon Energy's sample testing show that it has not failed the accuracy limits set out in Australian Standard 1284.13 and Chapter 7 of the NER.⁶⁷ Ergon Energy acknowledged that this was the case in an information response to us.⁶⁸ But it stated that the Warburton Franki meters should still be replaced given their advanced age; they were manufactured more than 50 years ago.⁶⁹ Similarly, it proposed the replacement of the Ferranti meter family because they were purchased in 1965.⁷⁰

In the absence of further evidence supporting their replacement, we do not consider age alone to be a good basis on which to replace a meter family. It has been noted that Australian Standard 1284.13 and Chapter 7 of the NER establish a rigorous regime for determining whether a population of meters needs to be replaced. We consider Ergon Energy's proposal to replace meters on the basis of age, circumvents that regime. It would also likely lead to the replacement of meters in excess of the distribution business' actual requirements. We therefore have only accepted the replacement of meters which are supported by actual data showing they have failed the prescribed accuracy limits.

16.2.5.2.6 Opex

We accept \$118.6 million in opex for annual metering services compared to Ergon Energy's proposed \$169.5 million (\$2014–15). This is about 70 per cent of the total proposed opex.

The following base, step and trend sections explain how we arrived at our alternative forecast for metering opex.

16.2.5.2.6.1 Base

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

With assessing historical expenditure, we consider Ergon Energy's base should be at least as efficient as its costs in previous years. We observed Ergon Energy's historic opex over a five year period.

⁶⁷ AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 3.

⁶⁸ AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 3.

⁶⁹ AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 2.

⁷⁰ AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 2.

Ergon Energy did not rely on RIN data for their historical opex:

The AER's Regulatory Information Notice (RIN) specifically separates out metering expenditure into a number of opex categories, however these categories are not aligned to the AER's F&A requirements, nor are they mutually exclusive or collectively exhaustive. Ergon Energy has therefore developed reasonable estimates of historical opex that align to its forecast in order to enable comparison.⁷¹

Ergon Energy's concerns appear to relate to our category analysis RIN data which does separate metering expenditure into particular opex categories (such as meter testing, scheduled meter reads, meter maintenance).

However, we have relied on economic benchmarking RIN data 'opex for metering'.⁷² We consider that this data is appropriate to determine historic metering opex because it is audited, prepared across distributors using consistent instructions and definitions. In particular, the definition of metering services is:

Type 5-7 Metering Services as defined in the National Electricity Rules. Metering Services includes the installation, replacement, operation and maintenance (including meter reading) of type 5 to 7 Meters.⁷³

We consider that the economic benchmarking RIN definition is sufficiently broad and does not in any way limit distributors from including any metering related costs to that category. Further, the economic benchmarking RIN data is submitted in accordance with current cost allocation methods, which means that overheads are already accounted for.

Consistent with our approach for standard control services, we examined the proposed base by applying benchmarking. To do this we used a partial performance indicator which compared Ergon Energy's proposed opex per customer against other non-Victorian distribution businesses in the National Electricity Market.

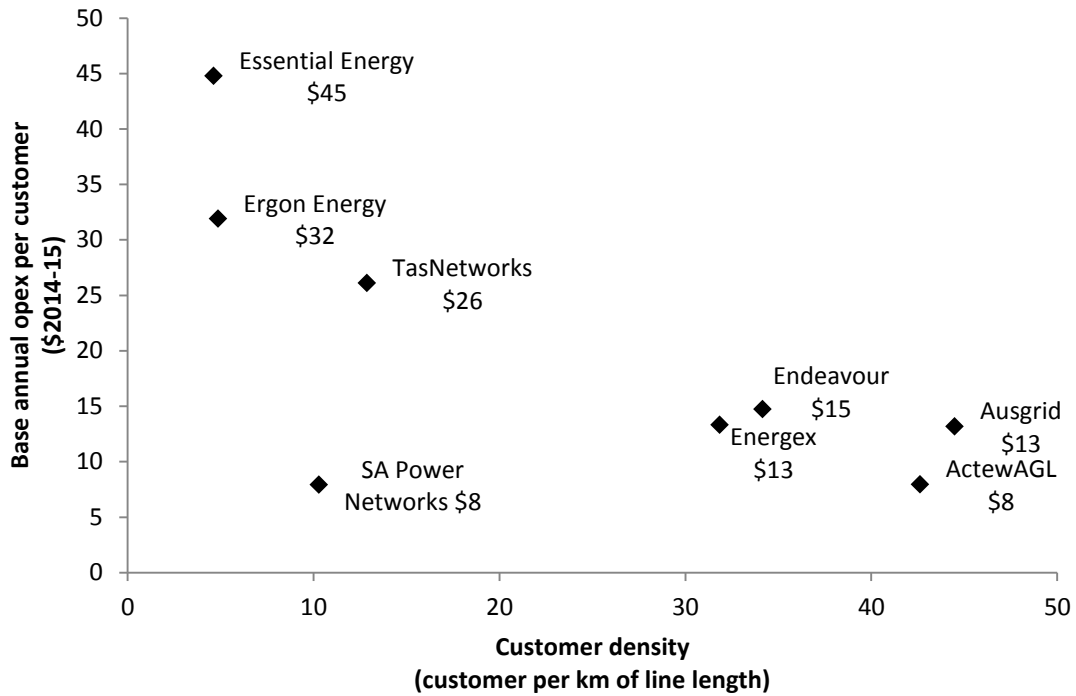
When comparing Ergon Energy's proposed opex to its peers, we normalised our results by accounting for customer density. We calculated this as the number of customers a distribution business has per kilometre of line length. We took customer density into account because, all things equal, businesses with a low customer density are likely to require higher opex. For example, this could be because of longer travel times to service customers. Figure 16.5 shows the results of our benchmarking.

⁷¹ Ergon Energy, Regulatory Proposal, 05.03.01 Default Metering Services Summary, p. 22.

⁷² Economic Benchmarking RIN responses, tab SD 3. Opex, table 3.2 opex consistency, row 'opex for metering'

⁷³ AER economic benchmarking RIN for distribution network service providers – Instructions and Definitions, p. 44.

Figure 16.5 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 Ergon Energy to require no more opex per customer than a distribution business with a similarly dense network. We therefore selected Essential Energy as the relevant comparator. In doing so, we observed that in the provision of metering services Ergon Energy incurs less opex per customer than Essential Energy. The former incurs \$32 on a per customer basis while the latter spends \$45. We conclude from this that, when normalising for customer density, Ergon Energy is relatively efficient.⁷⁴ As a consequence, we did not make an efficiency related adjustment to its base opex.

We have therefore accepted Ergon Energy's historical opex of \$32 per customer/year as the base for setting forecast opex in the 2015-20 regulatory control period.

16.2.5.2.6.2 Step changes

We do not accept Ergon Energy's proposed \$1 million step change for preventive meter maintenance in the 2015–16 year. Ergon Energy stated that this step change is required to meet regulatory obligations that the Australian Energy Market Operator has

⁷⁴ This not to say that Ergon Energy is as efficient as it could be; benchmarking only shows the relative efficiency across firms.

imposed on it. This is with respect to 'meter testing and conformance to defined accuracy parameters'.⁷⁵

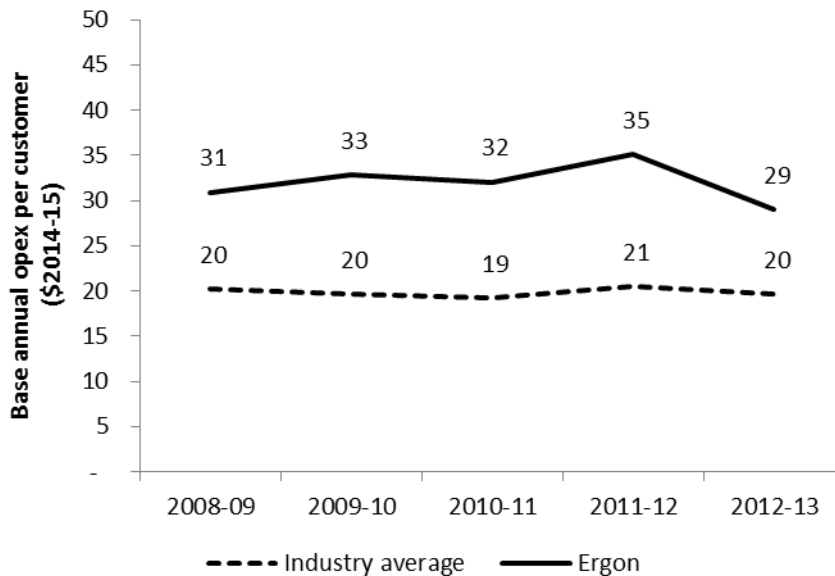
We approached AEMO about Ergon Energy's metering testing obligations. We were informed that the work associated with the proposed step change is not a new regulatory obligation.⁷⁶ For that reason, we do not accept Ergon Energy's proposal. As noted in our expenditure guidelines, step changes relate to a new obligation or some change in a service provider's operating environment beyond its control.⁷⁷ This is not the case in relation to Ergon Energy's proposed step change.

16.2.5.2.6.3 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.

Figure 16.6 Annual default opex per customer



However, Figure 16.6 shows that Ergon Energy's metering opex per customer was reasonably stable and dipped in 2012–13. The industry average was stable over the period. This implies that either there were no real price increases over this period, or

⁷⁵ Ergon Energy, *Regulatory proposal, Attachment 05.03.01: Default metering services summary*, November 2014, p. 24.

⁷⁶ Email from AEMO staff, 8 January 2015.

⁷⁷ AER, *Expenditure assessment guidelines*, November 2013, p. 11.

the distributors were able to offset these real price increases with productivity improvements.

Ergon Energy expressed a similar view:

Overall, historical opex has been relatively flat over 2010–15 in real terms, despite the volume of sites increasing by over 1% per annum over the period. This is due to Ergon Energy's productivity improvements implemented over the regulatory control period, including additional outsourcing where the market was more cost effective than internal resources.⁷⁸

Given that opex is largely recurrent and metering opex per customer has not been increasing, 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.

This arrives at an alternative opex forecast of \$118.6 million (\$2014–15).

16.2.5.3 Upfront charges

Ergon Energy's proposal did not include any upfront charges. Our preliminary decision, however, is to move the cost recovery of customer initiated capital works from the annual metering service charge to an upfront payment. This will be made directly by customers to Ergon Energy at the time of installation.

16.2.5.3.1 Policy reasons

By moving the cost recovery of customer initiated capital works, we have amended Ergon Energy'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. 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 and metering alterations and additions made by Ergon Energy. As noted in section 16.2.5.2, this preliminary decision is principally driven by the AEMC's metering rule change. When implemented, our approach to Ergon Energy's capitalisation policy (upfront payments) should help level the

⁷⁸ Ergon Energy, Regulatory Proposal, 05.03.01 Default Metering Services, p. 23.

competitive playing field for new meters. This is by shifting how Ergon Energy'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.⁷⁹ On this requirement, we note that Ergon Energy proposed \$35.7 million (2014–15) for new connections, metering alterations and additions in the 2015–20 regulatory control period, which we are not accepting. Notwithstanding, Ergon Energy 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.

16.2.5.3.2 Calculation of upfront charges

We have calculated the upfront capital charge for customer initiated capital works using Ergon Energy's proposed costs for similar work. Specifically, we have used the proposed costs for installation of an additional meter, which is classified in our F&A and in this preliminary decision as a 'quoted service'. We selected this quoted service because the installation of an additional meter involves the same type of activities as customer initiated capital works.

Ergon Energy's proposed costs for installation of an additional meter is 'based on an estimate of labour resources required to perform this service (a technical service person) and the use of a light commercial vehicle'.⁸⁰ It included a capital allowance, but not an allowance for materials or contractor services.

To calculate the upfront capital charge, we took Ergon Energy's proposed costs for installation of an additional meter, inclusive of the proposed labour and capital allowance, and added the forecast cost of materials. In adding the material costs, we established three charges. These are for single phase, dual element, and three phase type 6 meters. These material costs were derived from our consultant, Marsden Jacob, and represent the 'top end' of the observed market range for the category of meters Ergon Energy installs.⁸¹ Table 16.15 sets out our calculation of the upfront capital charge for Ergon Energy.

⁷⁹ NEL, Revenue and Pricing Principles, 7A (2).

⁸⁰ Ergon Energy, Regulatory proposal, Attachment 05.05.01

⁸¹ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1

Table 16.15 Upfront charge for customer initiated capital works (\$ nominal)

Meter	Materials	Labour	Capital allowance	Total
Single phase	100	250.18	43.45	393.63
Dual element	150	250.18	43.45	443.63
Three phase	189.27	250.18	43.45	482.90

Source: Ergon Energy, *Regulatory proposal, Attachment 05.05.01: Inputs and assumptions for ACS (redacted)*, November 2014, p. 34; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

We approached Ergon Energy about the calculation of the upfront capital charge. In an information response to us, Ergon Energy proposed separate charges for single, dual element, and three phase meters.⁸² We have implemented this, by adjusting for different material unit costs.

Ergon Energy proposed separate charges for urban and rural customers, to take into account longer travel times.⁸³ We have not accepted this aspect of Ergon Energy's proposal. Rather, we have applied a flat labour rate for all installation, which is consistent with Ergon Energy's proposal for ACS quoted services. It is also consistent with the proposed upfront capital charges Essential Energy proposed as part of its 2015–19 determination. We consider this to be significant because Essential Energy has similar network characteristics to Ergon Energy.

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.⁸⁴

Attachment A sets out the upfront capital charges we have approved in this preliminary decision.

⁸² Ergon Energy, AER Ergon 043, Email dated 16 April 2015.

⁸³ Ergon Energy, AER Ergon 043, Email dated 16 April 2015.

⁸⁴ See attachment 2 of this preliminary decision for more information on how changes in labour costs were forecast.

16.2.5.4 Metering 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 Ergon Energy'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.⁸⁵

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.⁸⁶

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.⁸⁷

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.⁸⁸ The

⁸⁵ 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.

⁸⁶ 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 March 2015, p.2; AGL, email to AER staff, AGL Presentation to AER staff—metering regulation & transition to competition, 13 March 2015.

⁸⁷ 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).

⁸⁸ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 1)p. 36.

retailer considered that a consistent approach to the calculation of administrative costs was most appropriate.⁸⁹

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.⁹⁰

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.⁹¹ 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.⁹² 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
- Banner system final read update—10 minutes.⁹³

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

⁸⁹ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 2), p. 7.

⁹⁰ Meeting between respective staff of Simply Energy and AER on 16 March 2015.

⁹¹ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

⁹² Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

⁹³ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

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 2015.⁹⁴ 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.⁹⁵ 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 16.16 where both organisations responses can be compared.

Table 16.16 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

⁹⁴ 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.

⁹⁵ 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.

Endeavour Energy Task	Endeavour Energy Time	Vector Comment
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 Table 16.16 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.⁹⁶ 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.⁹⁷

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 Ergon Energy (\$50.53 to \$63.44) 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

⁹⁶ Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

⁹⁷ Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015

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 will see Ergon Energy recover \$32 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.⁹⁸

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

16.2.6 Control mechanism

Our preliminary decision applies the control mechanism which we proposed in our final Framework and Approach for Ergon Energy.⁹⁹

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'.¹⁰⁰ Our preliminary decision, however, establishes a metering tariff structure which does not include such residual charges. Consequently, the A-factor has been set to zero.

16.3 Public Lighting

16.3.1 Preliminary decision

We do not approve Ergon Energy'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 Ergon Energy's proposal, including their LED transition plan.

⁹⁸ This logic also applies if we take the Ergon Energys' proposed average metering opex per customer per year of \$46.

⁹⁹ AER, Final Framework and Approach for Ergon Energy and Energex, April 2014, p. 96–97.

¹⁰⁰ AER, Final Framework and Approach for Ergon Energy and Energex, April 2014, p. 96–97.

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 16.7 sets out the control mechanism formulas for public lighting.

Figure 16.7 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 16.19.

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.

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 Ergon Energy's proposal

With the Queensland Government moving to cost reflective pricing for Ergon Energy councils, Ergon proposes to split its charges into:

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

Ergon Energy's proposed prices are set out in Table 16.17.

Table 16.17 Proposed prices for public lights, \$ per day

	2015—16	2016—17	2017—18	2018—19	2019—20
EO&O - Major	1.1355	1.1715	1.2086	1.2469	1.2864
EO&O - Minor	0.6768	0.6982	0.7203	0.7431	0.7666

	2015—16	2016—17	2017—18	2018—19	2019—20
GO&O - Major	0.4604	0.4750	0.4900	0.5055	0.5215
GO&O - Minor	0.3017	0.3113	0.3212	0.3314	0.3419

Source: Ergon Energy, 2015-20 Regulatory Proposal, p 52, table 27

Ergon Energy has also proposed an LED light transition plan and proposes to spend \$1 million per annum on this. Ergon Energy has proposed exit fees for councils who want to remove existing lights and transition more quickly to LED technology. The proposed exit fees, accounting for the remaining value of existing assets, are:

- \$1,390 for Ergon owned and operated major road lights
- \$840 for Ergon owned and operated minor road lights
- \$230 for council owned major road lights¹⁰¹
- \$195 for council owned minor road lights¹⁰²

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.¹⁰³ Concern is however raised over an increase in costs for Ergon Energy councils resulting from the removal of subsidies by the Queensland Government. What this means is a move towards cost reflective pricing.

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.

¹⁰¹ Exit fee proposed for council owned because Ergon Energy incurs refurbishment capital expenditure in respect of these assets.

¹⁰² Exit fee proposed for council owned because Ergon Energy incurs refurbishment capital expenditure in respect of these assets.

¹⁰³ LGAQ Submission, 30 January 2015.

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.

We accept the proposed changes to the breakdown of public lighting charges as this reflects an improvement in cost reflectivity for Ergon Energy, as they currently only have two public lighting charges; one major lights and another for minor lights.

The LED light transition plan of \$1 million per annum and the proposed exit fees for councils who want to transition more quickly to LED technology are accepted. LED is known technology that is being adopted due to their longer lamp life and operational savings they can provide to customers. Their life cycle costs are therefore considered by councils as superior to that of sodium high pressure and mercury vapour luminaires. They also outperform environmentally.

We consider the charges reflect the costs to Ergon Energy for those councils that want to transition existing street lights more quickly to LEDs. The LGAQ submission did not raise the issue of transitioning towards LED technology and the proposed exit fees.

The issue of moving towards cost reflective pricing is one for LGAQ members to work through with the Queensland Government. The AER has no control over the latter's policy positions on subsidised energy costs.

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. Ergon did not propose anything in relation to the treatment of the end of life of assets.

The preliminary decision implements a revenue reduction in 2015-16 of 6 per cent compared to a proposed increase of 4 per cent in the revised proposal. Preliminary decision revenue is set out in Table 16.18.

Table 16.18 Total revenue, millions

	2015—16	2016—17	2017—18	2018—19	2019—20
Proposed	32.9	34.2	35.9	37.5	38.8
Preliminary decision	29.7	30.9	32.5	34.0	35.3
change from previous year (percentage)	-6	4	5	4	4

Source: AER analysis.

Preliminary decision prices for each light type are set out in Table 16.19.

Table 16.19 Preliminary decision prices for public lights, \$ day

	2015—16	2016—17	2017—18	2018—19	2019—20
EO&O - Major	1.0252	1.0621	1.1062	1.1446	1.774
EO&O - Minor	0.6108	0.6320	0.6581	0.6804	0.6990
GO&O - Major	0.4140	0.4217	0.4376	0.4479	0.4528
GO&O - Minor	0.2712	0.2762	0.2867	0.2933	0.2964

Source: AER Analysis

A Approved charges

A.1 Ancillary Network Services

Table 16.20 Fee based services, preliminary decision

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
Application fee - Basic or standard connection	936.78	901.35	-3.8
Application fee - Basic or standard connection - Micro-embedded generators	52.86	46.95	-11.2
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	231.51	225.60	-2.6
Application fee - Real estate development connection	980.15	944.72	-3.6
Protection and Power Quality assessment prior to connection	1,429.21	1,429.21	-
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	607.18	607.18	-
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	971.49	971.49	-
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	607.18	607.18	-
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	971.49	971.49	-
Supply abolishment during business - urban/short rural feeders	364.31	364.31	-
Supply abolishment during business hours - long rural/isolated feeders	728.62	728.62	-
De-energisation during business hours - urban/short rural feeders	101.76	101.76	-

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
De-energisation during business hours - long rural/isolated feeders	607.18	607.18	-
Re-energisation during business hours - urban/short rural feeders	80.91	80.91	-
Re-energisation during business hours - long rural/isolated feeders	565.89	565.89	-
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	80.91	80.91	-
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	565.89	565.89	-
Accreditation of alternative service providers - real estate developments	937.92	937.92	-
Prevented access - one person crew - urban/short rural feeders	56.75	56.75	-
Prevented access - one person crew - long rural/isolated feeders	227.01	227.01	-
Prevented access - two person crew - urban/short rural feeders	116.89	116.89	-
Prevented access - two person crew - long rural/isolated feeders	467.56	467.56	-
Call out fee	Relevant service fee less total time on job	Relevant service fee less total time on job	NA

Table 16.21 Quoted services, preliminary decision

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
Application fee - Negotiated connection	1,166.42	1,119.18	-4.1
Application fee - Negotiated connection - Micro-embedded generators	515.88	498.16	-3.4
Application fee - Negotiated - Major customer connection	7,247.92	7,247.92	-

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
Carrying out planning studies and analysis relating to connection applications	2,289.56	2,289.56	-
Feasibility and concept scoping, including planning and design, for major customer connections	18,412.65	18,412.65	-
Tender process	10,719.09	10,719.09	-
Pre-connection site inspection	1,329.04	1,329.04	-
Provision of site-specific connection information and advice for small or major customer connections	783.93	783.93	-
Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates	9,647.18	9,647.18	-
Customer build, own and operate consultation services	76,409.23	76,409.23	-
Detailed enquiry response fee - EGs 5MW & above	25,541.81	25,541.81	-
Design and construction of connection assets for major customers	8,162,423.88	8,160,321.51	-0.03
Commissioning and energisation of major customer connections	44,147.62	44,088.57	-0.1
Design and construction for real estate developments	153,979.00	153,979.00	-
Commissioning and energisation of real estate development connections	6,760.83	6,760.83	-
Removal of network constraint for embedded generator	505,658.18	505,091.27	-0.1
Move point of attachment - single/multiphase	3,740.42	3,740.42	-
Re-arrange connection assets at customer's request	67,443.94	67,443.94	-

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
Protection and Power Quality assessment after connection	2,854.89	2,854.89	-
Temporary de-energisation - no dismantling	758.13	758.13	-
LV Service line drop and replace - physical dismantling	1,099.96	1,099.96	-
HV Service line drop and replace	4,538.35	4,538.35	-
Supply enhancement	1,296.50	1,296.50	-
Provision of connection services above minimum requirements	301,525.45	301,053.03	-0.2
Upgrade from overhead to underground service	8,722.99	8,722.99	-
Rectification of illegal connections or damage to overhead or underground service cables	220.23	220.23	-
De-energisation after business hours	147.06	147.06	-
Re-energisation after business hours	116.94	116.94	-
Accreditation of alternative service providers - major customer connections	6,580.62	6,344.40	-3.6
Approval of third party design - major customer connections	14,292.12	14,292.12	-
Approval of third party design - real estate developments	207.28	198.42	-4.3
Construction audit - major customer connections	92,745.73	92,745.73	-
Construction audit - real estate developments	1,181.00	1,181.00	-
Approval of third party materials	19,215.96	19,215.96	-
Special meter read	128.64	128.64	-
Meter test	455.13	455.13	-

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
Meter inspection and investigation on request	293.63	293.63	-
Metering alteration	2,903.46	2,903.46	-
Exchange meter	293.63	293.63	-
Type 5 to 7 non-standard metering services	416.09	416.09	-
Removal of a meter (Type 5 & 6)	138.26	138.26	-
Meter re-seal	594.61	594.61	-
Install additional metering	293.63	293.63	-
Change time switch	220.23	220.23	-
Change tariff	227.57	227.57	-
Reprogram card meters	1,321.35	1,321.35	-
Install metering related load control	293.63	293.63	-
Removal of load control device	293.63	293.63	-
Change load control relay channel	146.82	146.82	-
Services provided in relation to a Retailer of Last Resort (ROLR) event	2,936.69	2,848.11	-3.0
Non-standard network data requests	714.61	714.61	-
Provision of services for approved unmetered supplies	-	-	-
Customer requested appointments	764.04	764.04	-
Removal/rearrangement of network assets	312,283.92	312,283.92	-
Aerial markers	742.80	742.80	-
Tiger tails	2,498.14	2,498.14	-
Assessment of parallel generator applications	1,786.51	1,786.51	-
Witness testing	3,943.80	3,943.80	-

Service	Proposed price (\$2015–16)	AER preliminary decision (\$2015–16)	Difference (per cent)
Removal/rearrangement of public lighting assets	21,296.49	21,296.49	-

Labour Category	AER preliminary decision on maximum labour charge rates for quoted services, (\$2014–15)
Apprentice	N/A
Trainee	N/A
Power Worker	Confidential
Admin Employee	Confidential
Technical Service Person	Confidential
Electrical System Designer	Confidential
Supervisor	Confidential
Para-Professional	Confidential
System Operator	N/A
Professional Managerial	Confidential
Manager	N/A

Source: AER analysis.

A.2 Metering

Table 16.22 Annual metering charge – Preliminary decision (\$ nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19	2019/20
Primary	Non-capital	24.44	25.75	27.14	28.60	30.13
	Capital	6.49	6.84	7.21	7.59	8.00
Controlled load	Non-capital	8.99	9.47	9.98	10.51	11.08
	Capital	2.39	2.51	2.65	2.79	2.94
Solar	Non-capital	6.08	6.40	6.75	7.11	7.49
	Capital	1.61	1.70	1.79	1.89	1.99

Table 16.23 AER preliminary decision X factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	-2.76	-2.76	-2.76	-2.76

Source: AER analysis

Table 16.24 Upfront capital charges – preliminary decision

Meter	Upfront capital charge (\$ 2014–15)
Single phase	393.63
Dual element	443.63
Three phase	482.90

Source: AER analysis

Table 16.25 AER preliminary decision X factors for upfront capital charge (per cent)

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

Source: AER analysis.