



FINAL DECISION
Endeavour Energy distribution
determination
2015–16 to 2018–19

Attachment 16 – Alternative
control services

April 2015

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Note

This attachment forms part of the AER's final decision on Endeavour Energy's revenue proposal 2015–19. It should be read with other parts of the final decision.

The final 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 mechanisms

Attachment 15 – pass through events

Attachment 16 – alternative control services

Attachment 17 – negotiated services framework and criteria

Attachment 18 – connection policy

Attachment 19 – pricing methodology

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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
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model

Shortened form	Extended form
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

Ancillary network services are non-routine services distributors provide to individual customers on an 'as needs' basis.

In the 2009–14 regulatory control period, we classified ancillary network services as standard control services. Endeavour Energy called these 'miscellaneous' and 'monopoly' services. The Independent Pricing and Regulatory Tribunal (IPART) originally set the fees and labour rates for these services in 1999.¹ The fees have since been indexed by inflation (in 2009 labour escalation was also taken into account).²

As we discussed in the stage 1 F&A and affirm in this final decision, we classify ancillary network services as alternative control services.³

For the avoidance of doubt, this final decision refers to ancillary network services for which a charge is approved as 'fee-based services'. That is, we determined the fee using the cost of providing the service (labour rates) and the average time to perform the service. These services fees are fixed and apply irrespective of the actual time on-site to perform the service, even if that time varies from the benchmark we consider in this decision.

By contrast, quoted services are once-off and specific to a particular customer's request. The cost of these services will depend on the actual time taken to perform the service (rather than the benchmark we consider in this final decision). With the hourly rate set, the longer it takes the distributor to perform the service, the more the customer will pay.⁴

¹ IPART was the state regulator that made distribution determinations prior to economic functions being transferred to the AER on 1 January 2008.

² AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 57-58.

³ AER, *Stage 1 framework and approach paper: Ausgrid, Endeavour Energy and Essential Energy: Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, p. 32.

⁴ This is analogous to engaging a plumber to fix drainage problems in a house. The plumber's hourly rate is known in advance but the time taken to perform the fix is variable and will determine the final bill.

16.1.1 Final decision

We do not approve Endeavour Energy's revised proposed fees for ancillary network services.

Endeavour Energy's proposed fees are higher than fees based on maximum 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 contains final decision fees Endeavour Energy can charge for ancillary network services.

Table 16.17 sets out fees for fee-based services and Table 16.18 sets out labour rates for quoted services.

Form of control

Our final decision is to apply a price cap for the form of control to ancillary network services, consistent with the stage 1 F&A. 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 we set out in the draft decision⁵ and which Endeavour Energy agreed in its revised regulatory proposal.⁶

Form of control—fee based services

Under this form of control, we set a schedule of prices for the first year. For the following years the previous year's prices are adjusted by CPI and an X factor.

The form of control for fee based ancillary network services is:

Figure 16.1 Fee based ancillary network services formula

$$\bar{p}_i^t \geq p_i^t \quad i=1, \dots, n \text{ and } t=1, 2, 3, 4$$

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

Where:

\bar{p}_i^t is the cap on the price of service i in year t . For 2015–16 this is the price as determined in appendix A.1, escalated by ΔCPI and the X-factor.

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

⁵ AER, *Draft decision: Endeavour Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, pp. 13–15.

⁶ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 64.

$$\Delta CPI_t = \left[\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}} \right] - 1$$

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then *CPI* will mean an index which the AER considers is the best estimate of the index.

X_t^t is the value of *X* for the year *t* in the regulatory control period, as Table 16.1 sets out.

Table 16.1 AER final decision on X factors for each year of the 2015–19 period (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	-1.02	-1.07	-1.11	-1.10

Source: AER analysis.

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

\bar{p}_i^1 is the cap on the price of service *i* in the first year of the subsequent regulatory control period. See appendix A.1.

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

Form of control—quoted services

Figure 16.2 Quoted services formula

Price = labour + contractor services + materials

Contractor services (including overheads)—reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. The direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer. Contractor services are escalated annually by ΔCPI .

Materials (including overheads)—reflects 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 .

Labour is the maximum hourly charge out rate including on-costs and overhead.
Labour is escalated annually by $(1 - X_i)(1 + \Delta\text{CPI}_i)$.⁷

Table 16.2 sets out the escalation rates for each year that can apply to the labour rates.⁸

Table 16.2 AER final decision on labour escalation factor to apply to maximum labour charge out rates for quoted services (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	-1.02	-1.07	-1.11	-1.10

Source: AER analysis.

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

16.1.2 Revised proposal

Endeavour Energy did not revise its ancillary network services prices to reflect the draft decision's labour and overhead benchmarks. Endeavour Energy stated:

- its raw labour rates represent cost-reflective and efficient prices based on actual information
- its overheads are in accordance with the approved cost allocation method (CAM)
- there are examples of unreasonable outcomes in the draft decision.⁹

Endeavour Energy revised its proposed prices to reflect new labour escalators consistent with the revised standard control services forecast. It also updated the overhead factor based on the outcomes of the cost allocation method we approved.¹⁰

In response to our draft decision, Endeavour Energy also included a 'meter transfer fee' as part of ancillary network services in its revised regulatory proposal.¹¹ We consider this new fee in the metering section of this attachment.

16.1.3 Assessment approach

This final decision continues to adopt the draft decision approach of focussing on the key inputs in determining prices for ancillary network services. We considered:

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

⁸ Our opex rate of change attachment discusses the escalation factors.

⁹ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, pp. 245–248.

¹⁰ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 245.

¹¹ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, pp. 233–235.

- Endeavour Energy's revised proposal¹²
- Marsden Jacob's analysis of ancillary network services, including recommended maximum total labour rates for Sydney.

As with the draft decision, we consider labour is the key input in determining an efficient level of fees for ancillary network services. We focused on comparing Endeavour Energy's proposed total labour rates against maximum total labour rates for Sydney that Marsden Jacob developed. In this final decision, 'total labour rates' comprise raw labour rates, on-costs, and overheads.

Our final 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 and
- a maximum overhead rate

As we explain in more detail in section 16.1.4, Marsden Jacob obtained ranges (that is, minimum rates and maximum rates) for each of these components. Marsden Jacob then applied the maximum from these ranges to derive the maximum total labour rate.¹³ We consider that using Marsden Jacob's recommended maximum labour rates to determine appropriate fees for services will provide Endeavour 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.¹⁴

Where Endeavour Energy's proposed total labour rates exceeded the maximum total labour rates, we applied our maximum total labour rates to determine ancillary network services charges. Equally, we adopted Endeavour Energy's proposed total labour rates where they sat below Marsden Jacob's maximum total labour rates.

As a further check of our analysis, we also compared components of Endeavour Energy's proposed labour costs with those of the Victorian distributors. We consider the latter's costs generally closer to efficient levels.¹⁵

In coming to conclusions about the fees for Endeavour Energy's most frequently requested ancillary network services, we also assessed the times taken to perform the service.

¹² Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, pp. 244–248.

¹³ Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 1–6.

¹⁴ NEL, s7A and 16

¹⁵ Deloitte Access Economics, *NSW distribution network service providers labour analysis—Addendum to 2014 report*, April 2015.

In its revised proposal, Endeavour Energy took issue with our application of labour rates in the draft decision. We have addressed these specific issues in section 16.1.4 of this final decision.

16.1.4 Reasons for final decision

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

Our final decision prices for ancillary network services are generally lower than the prices Endeavour Energy included in its revised proposal (see Table 16.17 and Table 16.18). Our final decision prices are approximately 30 per cent lower on average than Endeavour Energy's revised proposal prices. These reductions reflect our assessment that Endeavour Energy's total labour rates are higher than the total labour rates that Marsden Jacob recommended for all labour categories.

In addition, our final decision's reductions to Endeavour Energy's ancillary network services fees are generally greater than the reductions in the draft decision (approximately 27 per cent, on average).¹⁶ This is because Endeavour Energy's revised proposal prices were generally higher than the prices in its original proposal. Endeavour Energy used a higher overhead rate in its revised proposal, which was a significant contributor to the higher prices.¹⁷

Endeavour Energy stated it does not consider benchmarking techniques 'are sufficiently refined to be relied upon to such a degree'.¹⁸ Endeavour Energy did not provide any persuasive evidence or critique of the techniques the draft decision relied upon to substantiate these general statements. As we noted in the draft decision, our

¹⁶ AER, *Draft decision: Endeavour Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, pp. 57–74.

¹⁷ Endeavour Energy, *Revised regulatory proposal: Attachment 8.05: ANS fee methodologies*, 20 January 2015.

¹⁸ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 245.

main concern is the cost inputs Endeavour Energy used in its methodologies.¹⁹ We consider Marsden Jacobs used robust methods and inputs to produce its recommended maximum total labour rates, as we set out in detail in the sections below.

Our assessment focussed on the inputs to the methods Endeavour Energy used to derive its fees for ancillary network services. In particular, labour is the major input to their proposed ancillary network services fees. We found proposed labour rates were inefficient. Hence, we adjusted Endeavour Energy's total labour rates where they exceeded the maximum total labour rates that Marsden Jacob developed and recommended (see section 16.1.3).

Each of the NSW and ACT distributors used different labour category names and descriptions. However, Marsden Jacob found that the types of labour distributors used to deliver ancillary network services broadly fell into one of five categories:

- Administration
- Technical services
- Engineers
- Field workers, and
- Senior engineers.²⁰

Table 16.3 shows the maximum total labour rates Marsden Jacob developed. We consider these maximum total labour rates should be used to assess Endeavour Energy's proposed charges for ancillary network services.

Marsden Jacob developed and recommended total maximum labour rates for each of these labour categories. They assessed raw labour rates (see 16.1.4.1), on-costs (see 16.1.4.2), and overheads (see 16.1.4.3) separately and derived maximum rates for each component. Marsden Jacob then applied these maximum rates to produce the maximum total labour rates.

We used these maximum total labour rates to determine whether Endeavour 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.

¹⁹ AER, *Draft decision: Endeavour Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, p. 17.

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

Table 16.3: Our final decision total labour rates (including on costs and overheads) (\$2014–15)

Category	Description	AER maximum total labour rates (\$2014–15)
Admin	Admin support	89.06
Technical	Technical specialist R2	142.81
Engineer	EO 7 / engineer	177.52
Field worker	Field worker R4	133.80
Senior engineer	Senior engineer	210.96

Source: Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 6 and 24.

Note: Endeavour Energy claimed confidentiality on its total labour rates.

Endeavour Energy stated utilising regulatory information notice data suggests that, amongst Australian distributors, its labour costs per employee represented the median. Endeavour Energy stated the benchmarks it produced are not necessarily reliable, but demonstrate that benchmarking can produce a spectrum of results.²¹

We agree that benchmarking can produce a spectrum of results because of differences in methods and inputs. However, it is important to consider benchmarking results only if they utilised robust methods and inputs. We consider we can use benchmarking results to determine revenues and/or prices in regulatory determinations where:

- the benchmarking methods and inputs are robust,
- where a distributor cannot justify labour rates that are high compared to the benchmarks

As we noted above, we consider Marsden Jacobs' analysis is robust and represents a prudent approach to assessing Endeavour Energy's labour rates. We discuss this in more detail in sections 16.1.4.1, 16.1.4.2 and 16.1.4.3.

16.1.4.1 Raw labour rates

In developing maximum raw labour rates (that is, excluding on-costs and overheads), Marsden Jacob examined Hays 2014 salary data. The Hays 2014 salary reports draw on information from 2,500 companies across Australia and New Zealand. Australian

²¹ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 245.

distributors in the Hays data (who gave permission to be named) were ActewAGL, Jemena, and CitiPower.²² The Hays rates draw from a wide pool of labour which Endeavour Energy would likely have access to. We therefore consider these rates provide a good representation of the competitive market rate for appropriate categories of labour.

Endeavour Energy stated its labour rates are substantiated by actual information and they represent a cost reflective and efficient price.²³

AGL, in a written submission, queried whether these labour rates are efficient or even a current reflection of the NSW labour market. It submitted that the NSW distributors provided no justification as to why local market conditions require much higher labour rates than other states. AGL supported our comparison of labour rates and on-costs against other states as an appropriate means of evaluation and analysis.²⁴

This echoes the Energy Users Association of Australia's submission not to allow the NSW distributors to effectively treat their negotiated labour rates in enterprise bargaining agreements as 'pass throughs'.²⁵

We do not assume that a wage deal struck through an enterprise bargaining agreement is automatically efficient. If the service provider expected us to use the costs revealed through its enterprise bargaining agreement as the starting point for determining total labour expenditure, it would not have an effective incentive for cost control, or for the efficient provision of services and the efficient use of the distribution system.²⁶ Effectively, that would make such expenditures akin to cost of service regulation, rather than the NER's emphasis on incentive regulation.

Discussed below, Marsden Jacob developed its recommendations using labour types and their respective rates that are available in a competitive labour market.

Endeavour Energy stated Marsden Jacob's analysis ignores the fact that it cannot access a national or international labour market.²⁷ It was not clear to Endeavour

²² 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

²³ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 245.

²⁴ AGL, *Submission on NSW distributors draft decisions*, 15 February 2015, p. 4.

²⁵ Energy Users Association of Australia, *Submission to NSW Electricity Distribution Revenue Proposals (2014/15 to 2018/19)*, 8 August 2014, pp. 9–10; Energy Users Association of Australia, *Submission to NSW DNSP revised revenue proposal to AER draft determination (2014 to 2019)*, 13 February 2015, p. 44.

²⁶ NEL ss. 7, 7A and 16; AER, *Final decision: Powerlink transmission determination 2012–13 to 2016–17*, April 2012, p. 52.

²⁷ Labour mobility is well understood in the mining industry. Skilled electricians are also available to any Australian distributor, no matter where that labour resides within Australia.

Energy whether the results are driven by lower labour rates in other states, countries or industries.²⁸

Marsden Jacob reviewed salary information from all Australian cities. However, they only used Sydney salary data to develop their recommended maximum raw labour rates in respect of the NSW distributors.²⁹ Marsden Jacob compared labour rates it developed using the Hays Sydney data against the Hays Melbourne data. Marsden Jacob did this as a cross-check to test the reasonableness of its recommended labour rates. Marsden Jacob found its recommended labour rates did not differ significantly from the Hays Melbourne raw labour rate data.

In its report, Marsden Jacob also included raw labour rates across the five labour categories for Brisbane and Auckland. Marsden Jacob included this data for illustration purposes—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 the Sydney rates alone were acceptable to develop maximum recommended labour rates for ancillary network service charges for the NSW and ACT distributors.

Marsden Jacob used job titles from Hays’ energy specific salary guide to develop maximum raw labour rates.³⁰ Marsden Jacob supplemented this with data from the Hays office support salary guide.³¹ This ensured that the ‘administration’ category was sufficiently covered.

Marsden Jacob analysed 66 different job titles, then used 36 of these to develop rates for the five labour categories.³² These 36 labour job titles involved tasks which clearly fell into either the 'administration', 'technical specialist', 'engineer', 'field worker', or 'senior engineer' labour categories. Marsden Jacob excluded job titles that were not relevant to electricity distributors such as 'wind farm engineer'. Table 16.4 shows the 36 job titles Marsden Jacob 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 16.4: Job titles Marsden Jacob used to develop maximum labour rates

Labour category		Job title
Admin	14 data points	Project secretary / Administrator
	(7 job titles)	Client liaison (residential)

²⁸ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 245.

²⁹ Marsden Jacob, *MJA analysis*.

³⁰ Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

³¹ Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

³² Marsden Jacob, *MJA analysis*.

		Data entry operator
		Records officer
		Administration assistant (12+ months experience)
		Project administration assistant (3+ years experience)
		Project coordinator
Technical specialist	22 data points	Technician
	(11 job titles)	Control room operator
		Control room manager
		E&I technician
		Protection technician
		Generator technician
		Operator / manager
		Site engineer
		Planner / scheduler
		OHS supervisor
		OHS manager
Engineer	14 data points	Design engineer
	(7 job titles)	Project engineer (EPCM)
		Power systems engineer
		Protection engineer
		Transmission line design engineer
		Asset engineer (3 to 7 years)
		Project engineer
Field worker	14 data points	Leading hand
	(7 job titles)	Electrician
		Mechanical fitter
		Line worker
		G&B lines worker
		Cable jointer
		Cable layer
Senior engineer	8 data points	Senior design engineer
	(4 job titles)	Principal design engineer
		Senior project engineer (EPCM)

Source: Marsden Jacob analysis

Marsden Jacob considered the range of data provided for each labour category across the various job titles. In doing this, it 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 Endeavour Energy would have access to in a competitive labour market. Marsden Jacob recommended using the maximum raw labour rate for each labour category to develop its maximum total labour rate.³³ 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 16.5: Marsden Jacob maximum raw labour rates

Marsden Jacob labour category	AER maximum raw labour rate (\$2014–15)
Admin	39.00
Technical	59.00
Engineer	69.00
Field worker	47.00
Senior engineer	82.00

Source: Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 2–3.

16.1.4.2 On-costs

Marsden Jacob recommended a maximum on-cost rate of 52.23 per cent. They developed a 'bottom up' estimate of on-costs applicable to the NSW and ACT distributors. Marsden Jacob did this for each of these businesses 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 NSW and the ACT

³³ Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 2–3.

- 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.

Based on these factors, Marsden Jacob calculated a maximum on cost rate for the ACT and NSW businesses of 52.23 per cent.³⁴ It then used this maximum on-cost rate to derive its maximum total labour rates. We consider this to be a prudent approach that is consistent with the revenue and pricing principles.

16.1.4.3 Overhead costs

Marsden Jacob applied the maximum overhead rates in Table 16.6 to derive its total labour rates.³⁵ In recommending these maximum overhead rates, Marsden Jacob compared the overhead rates the NSW and ACT distributors proposed (in their original regulatory proposals). Marsden Jacob found that Ausgrid and Endeavour Energy's overhead rates were significantly higher than those of Essential Energy, and ActewAGL. They were also significantly higher than the Victorian distributors' overhead rates.³⁶ Marsden Jacob therefore recommended maximum overhead rates 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.³⁷ This adds further support to using Marsden Jacobs' maximum overhead rates to calculate maximum total labour rates. We therefore consider that Marsden Jacob's total labour rates, which use the overhead rates in Table 16.6 as inputs, are prudent and appropriately reflect the revenue and pricing principles.

Table 16.6 Maximum overhead rates

Labour type	Maximum overhead rates (per cent)
Administration	50.0
Technical specialist	59.0

³⁴ Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 4.

³⁵ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

³⁶ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

³⁷ 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).

Engineer	69.0
Field Worker	87.0
Senior Engineer	69.0
Average overheads	65.0 ³⁸

Source: Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

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

- the nature of the differences in overhead rates may be due to differences in cost allocation methods
- 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.³⁹

Endeavour Energy highlighted this in its revised proposal and stated we did not apply Marsden Jacob's recommendation in full:

capping an overhead rate does have consequences for the CAM and our standard control service opex forecast. The overhead percentage allocated to a service is an output of applying the approved CAM and should not be utilised as an input. To cap the overhead and not provide for the recovery elsewhere is to effectively “strand” overheads and not permit the recovery of efficient costs. The AER should demonstrate how this approach is consistent with the CAM.⁴⁰

As we discussed in section 16.1.3, however, we assessed Endeavour Energy's total labour rates against Marsden Jacobs' total labour rates. We did not compare the individual components of total labour (raw labour, on-costs and overheads). The grand total, not the sum of its individual parts, was our method for determining labour rates.

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

³⁸ We used the figure of 65 per cent as inputs into Endeavour Energy's models where those services use a variety of labour types to derive a 'blended rate' and the total labour rates from those models exceed the total labour rates in Table 16.3.

³⁹ Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

⁴⁰ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 245.

National Electricity Law.⁴¹ 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.⁴² By extension, proper application of the cost allocation method does not indicate whether the resulting overhead rates represent efficient levels.

16.1.4.4 Unreasonable outcomes

Endeavour Energy provided examples where our application of Marsden Jacob's recommendations resulted in unreasonable outcomes in ancillary network services prices.⁴³

Disconnections (meter box)

Endeavour Energy stated our draft decision fee of \$63.94 for disconnections (meter box) is below that for a site visit of \$69.29. This is illogical as visiting the site and performing the work would take a greater amount of time than simply visiting the site.⁴⁴

This final decision has corrected this inconsistency that Endeavour Energy identified. As we set out in appendix A, our final decision includes the fee of \$165.69 (\$2014–15) for disconnections (meter box). However, the fee for a site visit is now \$55.02 (\$2014–15).

Origin submitted it understands Endeavour Energy combined re-energisation and de-energisation activities within the same fee. A number of submissions highlighted the inequity of this arrangement. Origin did not consider we provided a sufficiently clear explanation of how we assessed the concerns raised by stakeholders.⁴⁵ We noted in the draft decision Endeavour Energy's submission that:

the payment can cover multiple customers but this is very rare in their experience. This may occur if the disconnection occurs for one customer, but a different customer moves in and needs the power put back on. Endeavour Energy generally avoids this occurrence as it does not typically disconnect a customer on a move-out/final read. Endeavour Energy only tends to disconnect where a customer has not paid their bills or for those sites where access has proven difficult and the retailer requests physical de-energisation. Whilst Endeavour Energy does not specifically track this event, at a high level Endeavour Energy estimates that it would be less than one per cent of cases

⁴¹ AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

⁴² AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

⁴³ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 246.

⁴⁴ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 246.

⁴⁵ Origin, *Submission to AER draft determination for NSW electricity distributors*, 13 February 2015, p. 27.

where there is disconnection for one customer and another customer moves in to take over the site.⁴⁶

We note Endeavour Energy's proposed prices are higher than disconnection fees of the Victorian distributors. However, disconnection fees in Victoria are lower because most residential customers have smart meters and disconnections can be done remotely. This is not the case in NSW where smart meters do not exist for all households. Endeavour Energy's proposed disconnection/reconnection fees are consistent with those of the Tasmanian and Queensland distributors.⁴⁷ Like NSW, the Tasmanian and Queensland distributors have not rolled out smart meters to the same extent as in Victoria.

Reconnection/Disconnection (Meter load tail)

Endeavour Energy stated our draft decision used a lower labour rate of \$127.87 rather than our benchmark R4 labour rate of \$133.80 without justification.⁴⁸

We have corrected the input to our models such that we now use the labour rate of \$133.80. This is consistent with the approach we set out in section 16.1.3.

Reconnection/Disconnection (Meter load tail)

Endeavour Energy stated our draft decision included a fee of \$144.74 for reconnection/disconnection (meter load tail). On the other hand, our calculations suggested a fee of \$167.39.

This appears to have been an administrative error. The fees in appendix A reflect our calculations for this final decision.

Network tariff change requests

Endeavour Energy stated we did not approve the charge for 'network tariff change request' due to a definitional issue. In response to the draft decision, Endeavour Energy revised its definition for this service. The fee will now only apply to a valid network tariff change request that occurs outside of the annual pricing proposals process.⁴⁹

We maintain our draft decision to not adopt a charge for 'network tariff change requests'. This applies whether it is a valid or invalid request. We agree with AGL that this function sits with the distributor and customers should not be charged because the

⁴⁶ AER, *Draft decision: Endeavour Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, p. 25–26.

⁴⁷ In 2014–15, for example, Aurora charged a disconnection fee of \$53.77. Energex charged \$54.93 and \$70.30 (for site visit), while Ergon charged a disconnection fee for short rural of \$102.24 and \$592.66 for long rural.

⁴⁸ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 247.

⁴⁹ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 247.

distributor has not placed a customer on the correct network tariff.⁵⁰ Origin reiterated these points and supported our draft decision in its submission.⁵¹

Inconsistent application of labour rates

Endeavour Energy stated we applied Marsden Jacobs' labour rates in an inconsistent manner for the following services:

- Access (standby Person)
- Authorisations
- Connection offer service
- Customer interface co-ordination
- Recovery of debt collection costs

Endeavour Energy stated we used a mixture of Marsden Jacob labour or overhead rates with Endeavour Energy's labour or overhead rates where these are lower than Marsden Jacob's rates.⁵²

We refined our approach in this final decision such that it is consistent with our general approach of using total labour rates (see section 16.1.3).

Access permits

Endeavour Energy noted our calculations for access permit fees in the draft decision switched the rates for district operators and system operators. This resulted in a lower fee of \$2,108.48 rather than \$2,377.81.⁵³

We have corrected the calculations in our models and the fee for access permits is now \$2,377.81 (\$2014–15).

Clearance to work

Endeavour Energy stated it could not verify the draft decision fee for the 'clearance to work' service as Endeavour Energy did not have access to the calculation. It appeared to Endeavour Energy that we applied the same fee for 'clearance to work' as for 'access permits'.⁵⁴

⁵⁰ AGL, *NSW electricity distribution networks regulatory proposals: 2014- 19: AGL submission to the Australian Energy Regulator*, 8 August 2014, p. 32.

⁵¹ Origin, *Submission to AER draft determination for NSW electricity distributors*, 13 February 2015, p. 27.

⁵² Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 247.

⁵³ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 247.

⁵⁴ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 247.

The draft decision contained different fees for 'clearance to work' and 'access permits' (\$2,108.55 and \$2,108.48, respectively). However, there was an inputting error into the draft decision, as the correct fee for 'clearance to work' (for the draft decision) was \$2,004.73 (\$2014–15).

This final decision contains a fee of \$1,981.50 (\$2014–15) for clearance to work.

Franchise CT meter install

Endeavour Energy stated the draft decision fee for 'franchise CT meter install' used the 'Admin' labour rate. Endeavour Energy stated administration support staff cannot perform this work.⁵⁵

We agree and have used the rate for 'field worker' as the input to our calculation.

Site establishment fee

Table 16.17 sets out our final decision for Endeavour Energy's site establishment fee.

Endeavour Energy stated it currently levies the site establishment fee against the accredited service provider. Endeavour Energy is considering whether that approach should change. An MSATS system change was implemented in May 2014, with NMIs not published to MSATS until approved by the retailer. In its revised regulatory proposal, Endeavour Energy proposed levying the site establishment fee against the retailer, subject to Endeavour Energy's business processes. This is because the retailer must submit an 'Allocate NMI B2B service order'. Endeavour Energy stated it will consider this potential change further, including consultation with stakeholders, before it makes a final decision.⁵⁶

We note Endeavour Energy's intention to investigate whether it should levy the site establishment fee against the accredited service provider or the retailer. We consider the outcome should be in accordance with the requirement of the NER.

16.1.4.5 X factor in control mechanism formula

In its submission to the NSW distribution determination, Ergon Energy questioned whether it was appropriate for us to apply X factors consistent with our labour escalation factors. Ergon Energy stated this does not appear to take into account other drivers in real costs which may impact prices (such as contractor services and materials).⁵⁷

⁵⁵ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 248.

⁵⁶ Endeavour Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 246.

⁵⁷ Ergon Energy, *Submission on the draft decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, p. 38.

We consider it is appropriate to apply X factors consistent with our labour escalation factors because labour is the principal input into ancillary network services.

16.2 Public Lighting

16.2.1 Final decision

We do not approve Endeavour Energy's proposed public lighting charges because we have determined a real pre-tax WACC of 4.81 per cent instead of the proposed 7.34 per cent.

The AER accepts Endeavour Energy's:

- assumed 12 year life of LEDs
- a three/four year hybrid lamp bulk replacement program

Updated labour escalators have also been calculated and applied using the methodology adopted for the draft decision.

All other elements of the distributor's revised proposal public lighting charges have been accepted by us.

Form of control

Our final decision is to apply a price cap for the form of control to public lighting, consistent with the stage 1 F&A. Figure 16.3 sets out the control mechanism formulas for public lighting.

Figure 16.3 Public lighting formula

$$\bar{p}_i^t \geq p_i^t \quad i=1, \dots, n \text{ and } t=1, 2, 3, 4$$

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

Where:

\bar{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 appendix A.2.

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

$$\Delta CPI_t = \left[\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}} \right] - 1$$

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

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.

16.2.2 Endeavour Energy's revised proposal

In its revised proposal, Endeavour Energy accepted the draft decision methodology for calculating labour escalation.

Endeavour Energy did not accept the draft decision WACC and instead proposed a real pre-tax WACC of 7.34.

Endeavour Energy's revised proposal maintains its position of:

- 12 years as the appropriate assumed life of its LED
- a three/four year hybrid lamp spot replacement cycle

16.2.3 AER's assessment approach

The AER has continued with the assessment approach used in the draft decision. There were no submissions by councils on either the draft decision or Endeavour Energy's revised proposal in regards to public lighting.

16.2.4 Reasons for final decision

The reasons for the real pre-tax WACC of 4.81 per cent instead of the proposed 7.34 per cent are discussed in rate of return, attachment 3.

Whilst manufactures claims vary in relation to the performance of LEDs, Endeavour Energy presented evidence that the vast majority of manufactures cite a life of marginally below 12 years.⁵⁸ We accept that there is uncertainty about the life of new products like LEDs and that Endeavour's approach is reasonable in balancing the technological and financial risks to itself and its customers. No contrary evidence was presented to us by municipal councils or other stakeholders.

The draft decision set a four year bulk replacement benchmark for all lamps. We now however accept that distributors need to take account of their population of light types to ensure compliance with lighting standards. Given its light types, a three/four year bulk replacement of lamps is efficient for Endeavour Energy. The light types that are not compliant with a four year replacement cycle will need to continue to be replaced on a three year cycle.

⁵⁸ Endeavour Energy, Revised Regulatory Proposal, p. 229.

Labour escalators have been updated from the draft decision and are set out in Table 16.7 . The reasons for the final decision labour rates are discussed in opex, attachment 7.

Table 16.7 NSW Labour Escalators, per cent

	2013—14	2014—15	2015—16	2016—17	2017—18	2018—19
Draft Decision	0.58	0.89	0.87	1.40	1.62	1.44
Final Decision	na	1.34	1.02	1.07	1.11	1.10

Source: AER analysis.

Final decision prices for each light type are set out in appendix X. The lower WACC reduced tariff class 3 capital charges by an average 20 per cent and tariff 4 capital charges by an average 30 per cent in comparison to the revised proposal. The higher labour escalator in 2015-16 has resulted in an average 5 per cent increase in opex prices for tariffs 1 and 2.

16.3 Metering

Our final decision on Endeavour Energy’s metering proposal is made in the context of ongoing policy reform. We based our assessment on the National Electricity Rules (NER) in place at the time of this final 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.⁵⁹

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'.⁶⁰ Other key features of the draft rule change include:

⁵⁹ 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).

⁶⁰ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

- 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.⁶¹

Our final decision takes the AEMC's draft rule into account and establishes a regulatory framework for the 2015-19 regulatory control period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.⁶² This involves having transparent standalone prices for all new or upgraded meter connections and cost-reflective annual charges.

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

16.3.1 Final decision

16.3.1.1 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 final 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.

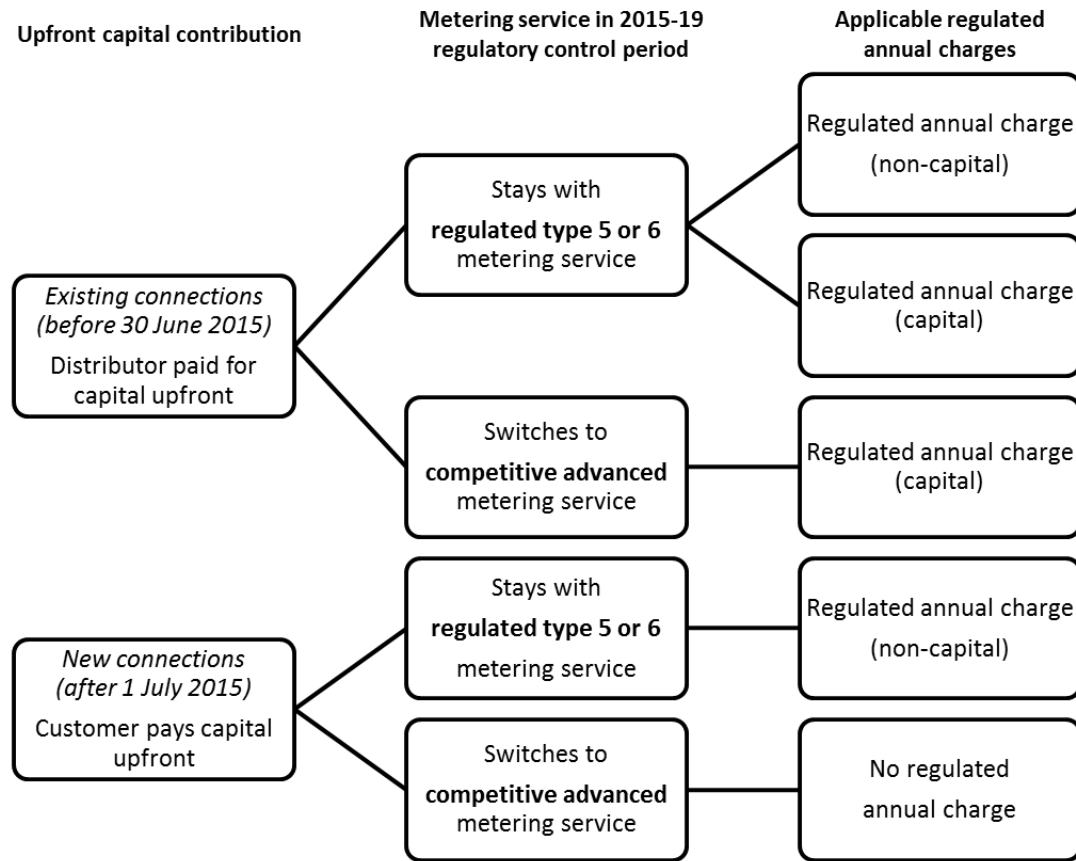
We have not approved a meter transfer fee relating to administrative costs associated with metering customers who switch to a competitive metering provider.

Figure 16.4 depicts how the two regulated annual charge components relate to different metering customers.

⁶¹ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. iii.

⁶² AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 79.

Figure 16.4 – Final decision – applicable regulated annual charges



Source: AER analysis.

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

Existing connections (before 30 June 2015)

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

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

- Capital (MAB recovery⁶³) component of regulated annual metering charge
- Non-capital (opex and tax) component of the regulated annual metering charge

⁶³ The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–19 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 16.4.

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 16.4.

16.3.1.2 Annual metering service charges

We generally accept Endeavour Energy's building block approach as the basis for establishing annual metering charges. With respect to each building block, our final decision is:

- Opening metering asset base

We considered the opening metering asset base (MAB) value. In its revised regulatory proposal, Endeavour Energy proposed an opening MAB value as a 1 July 2015 of \$18.8 million (\$ nominal) which our final decision is to accept.

- Depreciation

We do not accept the proposed remaining lives of Endeavour Energy's metering assets. Rather than its proposal for 5 year accelerated depreciation, we maintain our draft decision. This provides for a standard asset life of 15 years and a remaining asset life for existing metering assets of 23 years.

Consistent with our final decision for standard control services, we specify that forecast, as opposed to actual, depreciation will apply to Endeavour Energy's MAB.

- Forecast capex

We accept Endeavour Energy's proposed \$14.6 million (\$2014–15) in capex. This final decision is based on our assessment of Endeavour Energy's unit costs and revised forecast volumes. Endeavour Energy's revised capex is a 21 percent reduction from its initial proposal for \$18.5 million (\$2014–15).⁶⁴

- Forecast opex

Our cost assessment led us to accept \$71.7 million in opex⁶⁵ for annual metering charges and substitute that amount for the proposed \$108.9 million (\$2014–15). We used a base-step-trend approach to come up with our alternative forecast. To determine an efficient base, we considered that Endeavour Energy should be at least as efficient as comparable network businesses in the NEM.

Based on our cost assessment of the individual building blocks we rejected Endeavour Energy's proposed price caps for annual metering charges. Our substitute price caps are set out in Appendix A.

16.3.1.3 Upfront capital charges

We accept Endeavour Energy's proposed price caps for new or upgraded connections, which from 1 July 2015 will be recovered as an upfront charge to customers. The charges we have accepted are set out in Appendix A.

16.3.1.4 Meter transfer fee

⁶⁴ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 238.

⁶⁵ Exclusive of debt raising costs.

We do not approve a meter transfer 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.

16.3.1.5 Control mechanism

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

$$\bar{p}_i^t \geq p_i^t \quad i=1, \dots, n \text{ and } t=1, 2, 3, 4$$

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

Where:

\bar{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 Appendix A.

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

$$\Delta CPI_t = \left[\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}} \right] - 1$$

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

X_i^t is:

1. for the annual metering charges, the factors set out in Table 16.8.
2. for the upfront capital charges, the factors set out in Table 16.9.

Table 16.8 – Approved X-Factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19
X factor	-2.25	-2.25	-2.25

Source: AER analysis

Table 16.9 – Approved X-Factors for the upfront capital charges (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	0.0	0.0	0.0	0.0

Source: AER analysis

We will check for compliance with the control mechanism during the annual pricing process. To be compliant, Endeavour Energy must annually adjust individual price caps in accordance with the control mechanism formula shown above. Further, Endeavour 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.

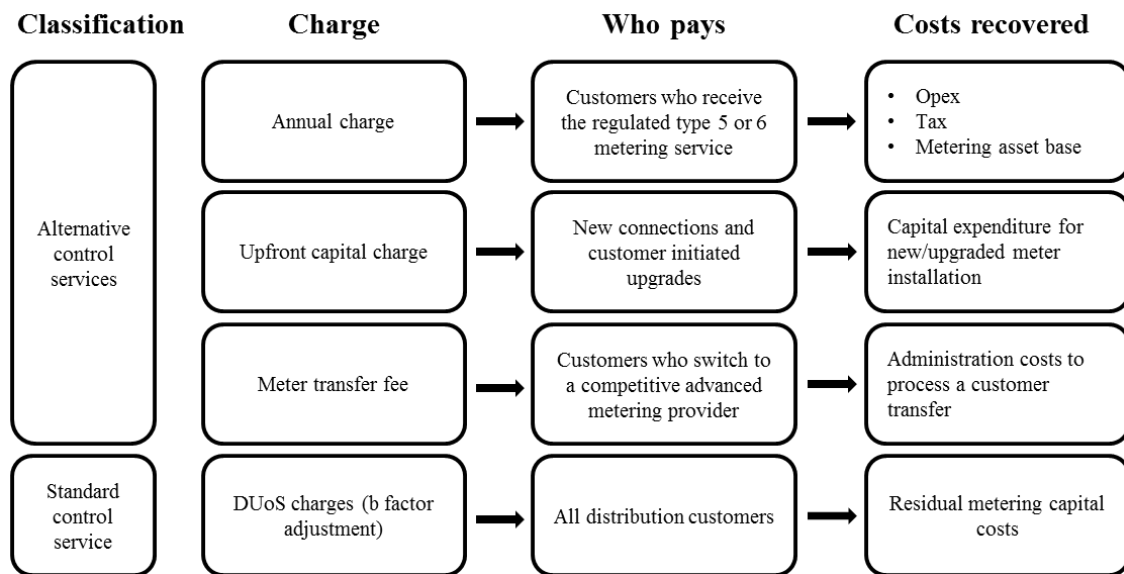
16.3.2 Endeavour Energy's revised proposal

In January 2015, Endeavour Energy submitted its revised metering proposal for the 2015–19 regulatory control period.

16.3.2.1 Structure of metering charges

Endeavour Energy had the following structure of metering charges in its revised proposal:

Figure 16.5 – Revised proposal – structure of metering charges



Source: AER analysis

Endeavour Energy's revised proposal was largely consistent with our draft decision.

The key change in charging structure from the initial to the revised proposal was that Endeavour Energy accepted our draft decision to recover residual metering capital costs across all distribution customers as a standard control service.⁶⁶

⁶⁶ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 233.

However, the revised proposal differed from our draft decision in two ways.

Firstly, Endeavour Energy rejected the tolerance limit on the b-factor adjustment 'unless the unrecovered amount can be carried forward to the next regulatory control period'.⁶⁷

Secondly, while Endeavour Energy noted our preference to have a separate annual charge for new and existing customers⁶⁸, it did not incorporate our proposed approach in its revised proposal.

16.3.2.2 Annual metering services

For each tariff class, Endeavour Energy proposed a price cap for annual metering services. It applied the 'building block' approach to develop the revenue requirements that are recovered through the proposed prices. This involved forecasting revenue requirement for each of the distribution business' metering related costs, comprising of:

- an opex building block—meter reading, meter data services and meter maintenance costs
- a capex building block—the cost of replacing existing meters either reactively or proactively
- the opening MAB recovery—the value of the existing metering assets as of 1 July 2014 and excludes replacements and the cost of new meter assets.

Endeavour Energy proposed to accelerate depreciation of the opening MAB so that the entire amount would be recovered by the end of the 2014–15 and 2015–19 regulatory control periods.⁶⁹ Endeavour Energy also proposed to apply one year accelerated depreciation for replacement capex in order to mitigate the risk of further stranded costs. It stated that 'given the relatively small size of [Endeavour Energy's] existing asset base it can be depreciated over an accelerated period of time without a material impact on prices and therefore customers'.⁷⁰

Endeavour Energy accepted our draft decision to use a historical average rather than a single year for the base opex calculation. It nonetheless raised a number of concerns with our base opex benchmarking approach. These related to:⁷¹

- the disparity in the extent of the benchmarking reduction—our draft reduced Endeavour Energy's opex for standard control services by 23 percent but its metering opex by more (34 percent)

⁶⁷ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 234.

⁶⁸ AER, *Draft Decision, Endeavour Energy distribution determination 2015-16 to 2018-19*, November 2014, p. 16–28. Under our suggested approach, new customers who pay for their capital costs upfront will have an annual charge that does not include capital costs (opex and tax only). Existing customers who did not pay for their capital costs upfront, will pay an annual charge that includes capital costs.

⁶⁹ Endeavour Energy, *Revised regulatory proposal*, January 2015, p. 243.

⁷⁰ Endeavour Energy, *Revised regulatory proposal*, January 2015, p. 243.

⁷¹ Endeavour Energy, *Revised regulatory proposal*, January 2015, p. 238–9.

- what appeared to be our draft decision assuming a linear relationship between customer density and opex per customer
- Endeavour Energy's claim that Energex is not a reasonable comparator because:
 - Energex has greater economies of scale
 - the cost of living differences between QLD and NSW impact on labour rates
 - there are other organisational and environmental differences, in addition to customer density, that have not been accounted for
 - Energex's lower metering opex costs may be driven by differences in cost allocation methodologies, rather than efficiency.
- Endeavour Energy also included the following opex step changes which it did not put forward in its initial regulatory proposal:⁷²
- positive step changes relating to recently adopted national energy customer framework (NECF) and asbestos management compliance obligations
- negative step change for special meter reading and meter accuracy testing opex which have historically been included in metering expenditure, but in future will be recovered in ancillary network service charges.

Table 16.10 sets out Endeavour Energy's proposed metering building block revenue requirement. Table 16.11 shows the proposed annual charges for metering services that recover the total proposed revenue.

Table 16.10 – Endeavour Energy's proposed metering revenue requirement (\$ million, 2014–15)

	2014–15	2015–16	2016–17	2017–18	2018–19
Opex	19.64	21.87	21.89	22.65	22.67
Replacement capex	2.82	3.42	3.10	2.51	3.40
Opening RAB recovery	4.92	4.69	4.57	4.55	4.63
Total proposed	27.37	29.98	29.56	29.71	30.70

Source: Endeavour Energy, *Revised regulatory proposal, Attachment 8.04, Revised metering model and price list*, January 2015. Converted to \$2014-15.

Table 16.11 – Endeavour Energy's proposed prices for annual metering services (\$2014–15)

Tariff class	Average price per annum (2014–15 to 2018–19)

⁷² Endeavour Energy, *Revised regulatory proposal*, January 2015, p. 240.

Residential anytime	25.29
Residential time of use – Type 6 meter	48.58
Residential time of use – Type 5 meter	185.29
Small business anytime	35.50
Small business time of use – Type 6 meter	79.22
Small business time of use – Type 5 meter	215.92
Controlled load	10.66
Solar	10.66

Source: Endeavour Energy, *Revised regulatory proposal, Attachment 8.04, Revised metering model and price list*, January 2015. Converted to \$2014-15.

16.3.2.3 Upfront capital charges

Where a customer obtains a meter as a result of a new or upgraded connection, Endeavour Energy proposed caps (or ceilings) on the prices it can charge.⁷³ From 1 July 2015, the proposed prices would be charged as an upfront capital charge.

Table 16.12 sets out the proposed new or upgraded connection prices. The figures shown are for the 2014–15 year. They will be adjusted each year for CPI.

Table 16.12 – Endeavour Energy's averaged proposed new or upgraded meter prices in the 2015–19 period (\$2014–15)

		Interval (3G modem)	Interval (without 3G modem)	Accumulation
Whole current single element meter	Single phase	650.55	85.98	40.82
	Single phase import/export	650.55	85.98	85.98
	Poly phase	462.95	266.13	110.42
	Poly phase import/export	462.95	266.13	112.14
Current transformer meter	Single phase	N/A	N/A	N/A
	Single phase import/export	N/A	N/A	N/A
	Poly phase	560.30	363.48	363.48
	Poly phase	560.30	363.48	363.48

⁷³ Endeavour Energy, *Revised regulatory proposal, Attachment 8.04, Revised metering model and price list*, January 2015.

	import/export			
	Single phase	741.60	177.04	177.04
Whole current dual element meter	Single phase import/export	741.60	177.04	177.04
	Poly phase	N/A	N/A	N/A
	Poly phase import/export	N/A	N/A	N/A

Source: Endeavour Energy, *Revised regulatory proposal, Attachment 8.04, Revised metering model and price list*, January 2015

16.3.2.4 Meter transfer fee

Endeavour Energy proposed a meter transfer fee per meter of \$64.91 (\$2014–15)⁷⁴ to recover administration related costs of processing a customer transferring to an alternative metering provider.

Endeavour Energy questioned our decision to not use our consultant Marsden Jacob's recommendation for a benchmark meter transfer fee by stating that it considered it "unreasonable to have rejected our proposed fee and set it at \$0 when an alternative, independent estimate was available."⁷⁵

16.3.2.5 Control mechanism

Endeavour Energy did not agree with our draft decision to set X-factors at zero. It noted that we allowed real labour escalators for ancillary network services, and considers they should apply to metering services as well.⁷⁶

16.3.3 Assessment approach

Endeavour Energy has proposed price caps on three categories of metering services. These are annual metering services, upfront capital charges for new or upgraded connections, and a meter transfer fee.

16.3.3.1 Structure of metering charges

AEMC Draft Rule Change

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.⁷⁷

⁷⁴ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 235.

⁷⁵ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 235.

⁷⁶ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 243.

⁷⁷ AEMC, *Draft Rule Determination (Expanding competition in metering and related services)*, 26 March 2015, p. 225

National Electricity Law

We had regard to the national electricity objective and the revenue and pricing principles which include providing a distribution business with a reasonable opportunity to recover at least its efficient costs.⁷⁸

National Electricity Rules

We had regard to the distribution pricing principles set out in 6.18.5 which includes the requirement that revenue recovered should be between standalone and avoidable cost of serving that customer group.

In determining the appropriate structure of metering charges we have made decisions on the classification of the service and the control mechanism. The classification and control mechanism to recover metering capital costs that risk becoming stranded if a customer switches was not explicitly considered in our Stage 1 Framework and Approach.⁷⁹ Our final decision classification and control mechanism has been made with regard to the factors set out in clauses 6.2.2(c) and 6.2.5 (c) of the NER. We had particular regard to:

- how the classification/control mechanism may influence the potential for competition in unregulated metering
- a method that provides administrative simplicity for customers, Endeavour Energy and the AER where possible
- the extent to which costs can be directly attributable to individual customers in order to minimise cross subsidies.

We also have a preference for a nationally consistent approach. Our approach to the classification of services is discussed in Attachment 13.

16.3.3.2 Annual metering service charges

We assessed Endeavour Energy's proposed opening MAB, depreciation, capex and opex components associated with the annual metering service.

Opening metering asset base

In assessing Endeavour Energy's proposed opening MAB, we reviewed how Endeavour Energy had separated its proposed opening metering regulatory asset base (RAB) as at 1 July 2014, from the RAB for standard control services.

⁷⁸ NEL, Revenue and Pricing Principles, 7A (2).

⁷⁹ NER, cl. 6.12.3 (b) (cl). We may depart from the classification and control mechanism decisions made in our framework and approach paper if we consider there have been unforeseen circumstances. The unforeseen circumstance in this case was that there previously was no stranding risk because customers had no choice to exit regulated metering. As such, we did not consider residual metering costs in our framework and approach paper (March 2013) which was released prior to SCER metering rule change request (October 2013).

Depreciation

With respect to depreciation, we considered the remaining asset lives Endeavour Energy proposed and had regard to the opening of competition to metering services.

Forecast capex

In assessing the proposed forecast capex, our assessment approach did not change from our draft decision. We reviewed Endeavour Energy's unit costs and volume forecasts. More specifically, we assessed Endeavour Energy's proposed 'material' and 'non-material' unit costs and the forecast volume of reactive and proactive replacements. Material costs relate to the hardware used to provide metering services. Non-material costs relate to the labour activities which Endeavour Energy must perform to install a new or replaced meter.

From 1 July 2015, Endeavour Energy's customers will incur an upfront payment recovering the capital cost of meters installed at 'new or upgraded connections'. The commencement date for the upfront payment (1 July 2015) is the earliest available under the NER. This provides that the existing cost allocation approach leading up to the placeholder year must be retained into 2014–15.⁸⁰ In the case of new or upgraded connections, the capital cost of the meters must be recovered under the general network charge for standard control services. However from 1 July 2015, Endeavour Energy proposed to change its capital contribution policy so that such costs are recovered directly from customers.

New or upgraded connections in 2014-15 formed part of our assessment of Endeavour Energy's proposed capex building block for annual metering services. However the 'true-up' of any differences between the capital costs Endeavour Energy recovered in the 2014–15 placeholder year with our assessment of what we consider to be prudent and efficient will be recovered under the general network service charge.

Forecast opex

We applied the same approach to assessing Endeavour Energy's proposed opex, as in our draft decision.

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

After determining Endeavour Energy's efficient base opex, and accounting for any (positive or negative) step changes, we trended forward that amount over the 2015–19 regulatory control period. This is known as the 'base, step and trend' approach.

Base

As opex is largely recurrent in nature, we considered Endeavour Energy's historical costs to be a useful starting point to establish a base to forecast future costs. We also

⁸⁰ NER, cl. 6.15.2(7).

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.⁸¹

Our metering assessment relates to annual charges for default metering services common to all regulated type 5 and 6 metering customers. 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. We did not make this adjustment for the draft decision, but have adjusted base metering opex data to exclude ancillary metering service costs for the final decision.

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 distributors⁸² 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.

As with our draft decision, we adjusted the benchmarking results for customer density. This is a network characteristic exogenously influences opex requirements.

We also took Endeavour Energy's revised regulatory proposal into account. In particular, we considered if Endeavour Energy had demonstrated whether any further exogenous influences, other than customer density, should be taken into account.⁸³

⁸¹ AER, Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample, November 2013.

⁸² Victorian distributors rolled out advanced metering technology in the last regulatory period. These costs are not comparable to other distributors which have type 5 and 6 meters.

⁸³ AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–43.

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.⁸⁴ Our assessment approach is consistent with our *Expenditure forecast assessment guideline*.⁸⁵

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.

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.⁸⁶ 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.⁸⁷

16.3.3.3 Upfront capital charge

To assess the reasonableness of the proposed charges from 1 July 2015, we analysed Endeavour Energy's unit costs. We did not consider the forecast volumes of new or upgraded connections for the 2015–19 regulatory control period; they have no bearing on the quantum of the upfront charge.

⁸⁴ NER, clause 6.6.5(c).

⁸⁵ AER, *Expenditure assessment forecast guideline*, November 2013, p.11, 24.

⁸⁶ NER, cll. 6.5.6 and 6.5.7.

⁸⁷ NER, cll. 6.5.6(c) and 6.5.7(c).

16.3.3.4 Meter transfer fee

Our draft decision did not make an explicit decision on the meter transfer fee proposed by Essential Energy. It sought more evidence from distributors as to the quantum and rationale for these fees. Stakeholders' views were also sought.

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.⁸⁸

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.

16.3.4 Interrelationships

Our final decision should provide Endeavour Energy with an opportunity to recover at least its efficient costs.⁸⁹ 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 final decision on Endeavour Energy's alternative control metering proposal, therefore, interrelates with our assessment of its proposed rate of return. Refer to attachment 3 of this final decision for the rate of return we accept for direct control services,⁹⁰ 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 16.3.1.5.

⁸⁸ Australian Energy Market Commission, Draft rule determination, Expanding competition in metering and related services, 26 March 2015.

⁸⁹ NEL, Revenue and Pricing Principles, 7A (2).

⁹⁰ Direct control services include standard and alternative control services.

16.3.5 Reasons for final decision

Our reasons for decision on the structure of metering charges, annual metering service charges, upfront capital charges for new or upgraded connections, and the meter transfer fee are discussed in this section.

16.3.5.1 Structure of metering charges

Our final 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 2015–19 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 is 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.⁹¹

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.*"⁹² 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.

Endeavour Energy (and other distributors) initially proposed to charge 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.⁹³ 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.⁹⁴ 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.

⁹¹ 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.

⁹² QCOSS, *Submission to AER Consultation Paper (Recovery of Residual Metering Costs)*, 31 March 2015, p 2

⁹³ 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.

⁹⁴ Vector Limited, *Submission on DNSPs regulatory proposals*, 8 August 2014 p. 4.

There are several methods of ensuring distributors can recover capital costs incurred in providing regulated metering services. After extensive consultation with stakeholders⁹⁵, we decided on a method that we considered best balances the objectives of distributors and customers and meets regulatory objectives to promote competition in metering services.

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

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

Our draft decision involved recovering residual metering capital costs through charges for standard control services based on actual customer switching. These residual capital costs would then be recovered from the general distribution customer base through making a b-factor adjustment to annual revenue requirements, which would have the effect of (all things equal) increasing network tariffs. To mitigate network tariff price volatility that may arise if many customers switched in the one year, we proposed a tolerance limit on the b-factor.⁹⁶

Our draft decision approach received wide support from most stakeholders.⁹⁷ Despite having some reservations, NSW distributors largely accepted our draft decision, but did

⁹⁵ In addition to our normal consultative process which allows stakeholders to provide submissions on the distributor's proposal and our draft decision, we also held a metering workshop on 11 September 2014 and released a consultation paper (on the alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge) in March 2015. We received submissions from consumer groups, potential competitive metering providers, retailers and distributors.

⁹⁶ AER, *Draft Decision, Endeavour Energy distribution determination 2015-16 to 2018-19*, November 2014, p. 16–46.

⁹⁷ Vector Limited, *Submission on the AER's Draft Decisions on NSW and ACT Electricity Distributors' Regulatory Proposals for 2015-16 to 2018-19*, February 2015, p. 3.

not agree with the operation of the b-factor and the tolerance limit. ActewAGL did not support our approach primarily on the basis that there may be legal concerns on whether our draft decision approach would be permissible under the NER. In particular, whether residual capital costs can be recovered through standard control services in the way proposed. Ergon Energy shared the same concern.⁹⁸

In response to the concerns raised, we consulted on alternatives that would not require moving residual capital costs through to the standard control RAB.⁹⁹ We settled on our final decision approach because it responds to and addresses the main concerns raised by the NSW and ACT distributors and in our view also better meets the national electricity objective.

Distributors recover the same amount overall under both our draft and final decision approaches. The difference is which particular customer class pays. Under our draft decision, a switching customer did not directly have to pay for the residual metering capital costs related to their regulated metering service. Instead, residual capital costs would be recovered from all distribution customers through network (DUoS) tariffs, including larger customers who have never received these metering services. Switching customers only indirectly paid for a small fraction of the residual metering capital costs through the increase in network tariffs (the same increase faced by all distribution customers).

This has been amended in our final decision, such that a metering customer switching from the distributor directly shares in the recovery of residual capital costs associated with their past regulated metering service with all other metering customers. They do so by continuing to pay the same capital component of the regulated annual charge as all other metering customers until the metering asset base is fully depreciated.

Our final decision addresses the NSW businesses concerns because it ensures steady cost recovery without the need for annual corrections through a b-factor adjustment or the application of tolerance limits. It also avoids the potential legal concerns raised by ActewAGL.

We consider our final decision to have switching customers continue to pay for the capital costs associated with the regulated metering service, on balance, better meets

ERAA, *Submission on NSW DNSPs draft decision*, 13 February 2015, p. 1.

Origin, *Submission on NSW draft decisions*, 15 February 2015, p. 22.

CCP, *Submission to AER Responding to NSW draft determination and revised proposals*, February 2015, p.41.

AGL, *Submission to AER on NSW electricity distribution network determinations 2014-19: AER draft decisions and revised regulatory proposals*, February 2015, pp.1-3.

TEC, *Submission to AER on the draft determination on NSW DB's regulatory proposals 2014-19*, February 2015, p.2.

NCOSS, *Submission to the AER draft determination on NSW distribution business's revised regulatory proposals 2014-19*, February 2015, p.7.

⁹⁸ Ergon Energy, *Submission on the draft decisions: NSW and ACT distribution determinations 2015-16 to 2018-19*, February 2015, p. 35.

⁹⁹ AER, *Consultation paper - Recovering the residual metering capital costs through an ACS annual charge*, March 2015.

the regulatory objectives under the NEL and NER, than either Endeavour Energy's initial proposal or our draft decision approach. We considered:

- Impact on competition
 - The structure and quantum of regulated metering charges impact competitive entry (both upfront exit fees and the regulated annual charge).
 - Like our draft decision, our final decision removes the upfront exit fee which was identified as the primary barrier to competitive entry by stakeholders.
 - Like our draft decision, our final 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 final decision, the customer is charged the capital component of the regulated annual metering charge directly.
 - Relative to our draft decision, our final decision increases the costs to switch to a competitive metering provider.¹⁰⁰ A higher switching cost relatively lowers the incentive to switch to a competitive metering provider, so our final decision approach may result in slightly slower uptake of competitive metering services, depending on how compelling an offer is by a competitive metering provider.
- Administrative simplicity:
 - Our final decision makes use of existing information that Endeavour Energy has, rather than relying on further information on the remaining economic or technical life of individual metering assets which would be difficult to determine.
 - It is less complex than the draft decision which involved making annual adjustments to the b-factor and the standard control services RAB. Further, tolerance limits are no longer needed because there will be no price volatility under our final decision approach.
- The directly attributed cost to minimise cross subsidies.
 - Our final 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

¹⁰⁰ Under our draft decision, a customer who switched only had to pay metering charges related to a competitive metering provider for their new advanced meter and a small proportion of residual metering capital costs through increased DUoS charges. Under our final decision, a customer who switches continues to pay the regulated annual charge (capital), in addition to any new advanced metering charge. The switching cost is therefore higher under our final decision.

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.

- Our draft decision involved cross subsidising residual costs across the general distribution customer base. For example, the network tariff paid by a large industrial customer who has never used a type 5 or 6 regulated metering service¹⁰¹ would contribute towards paying off residual metering capital costs associated with switching customers.
- Under our final 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 final 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.¹⁰² 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 2017.¹⁰³
- Our final decision to charge for new and upgraded meters upfront removes the risk of future cross subsidy. This is because by charging capital costs upfront, it is directly attributed and paid for by the customer choosing to install that meter. There is no risk of metering capital costs becoming stranded.

Our final decision signals a relatively higher switching cost compared to our draft decision as we explain above. This may result in slower entry by competitive entrants

¹⁰¹ Type 5 and 6 metering services are for smaller customers who consume less than 160MWh annually.

¹⁰² 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.

¹⁰³ AEMC, *Expanding competition in metering and related services, Draft Rule Determination*, 26 March 2015, p. 79.

than our draft decision. However, we consider it appropriate that our final decision signals a lower avoidable annual cost for two reasons.

Firstly, the avoidable cost signalled under our final decision is closer to the actual avoidable cost faced by the distributor. Actual avoidable costs are variable costs the distributor no longer incurs when a customer switches. Non-capital costs (for example, meter reading) are largely variable costs. Under our existing regulatory framework, distributors are entitled to recover capital costs incurred in providing regulated metering services. Thus, the recovery of capital costs cannot be avoided even if a customer switches.

Our draft decision therefore signalled a higher than actual avoidable cost to the switching customer, which arguably might promote greater switching than what is efficient. Under the draft decision, the avoidable cost signalled to the switching customer was equal to the entire annual charge (based on both the variable non-capital and fixed capital components). Under the final decision, the avoidable cost is only the variable non-capital component of the annual charge, closer to the true avoidable cost.

Secondly, the impact on competition is not the only regulatory objective. We are required to balance a number of considerations under the NER, including the need for efficient price signals and thus minimising cross subsidies. When making our draft decision, we accepted this cross subsidy (which resulted in the relatively higher avoidable annual costs). This was preferable to the alternative of accepting a large exit fee because of the negative impact on competition. However, we consider that our final decision better balances the various objectives than both our draft decision and the initial proposal from network businesses to charge a high upfront exit fee. Our final decision removes the main barrier to competition (a high upfront exit fee) while being administratively simpler and minimising cross subsidies and therefore leading to a more efficient outcome.

16.3.5.2 Annual metering service charges

- Our final decision is to not accept Endeavour Energy's total proposed building block requirement for annual metering services. We maintain our draft decision accepting a building block approach to setting charges. We also accept the proposed:
 - opening MAB
 - forecast capex.

However, we do not accept Endeavour Energy's approach to depreciation or its forecast opex for annual metering services. This has led us to revise the proposed annual metering service charges.

Our substitute price caps are set out in appendix A.

Opening metering asset base

- Our final decision is to accept Endeavour Energy revised opening MAB value as at 1 July 2015 of \$18.8 million (\$nominal). We are satisfied that the opening value has

been correctly separated out from the regulatory asset base (RAB) for standard control services.

- The revised opening MAB value is lower than the amount initially proposed (\$22.7 million). This is due to the incorporation of 2013–14 actuals in the roll forward model.¹⁰⁴

Depreciation

- Consistent with our final decision for standard control services, we specify that forecast, as opposed to actual, depreciation will apply to Endeavour Energy's MAB.
- We do not accept the proposed remaining lives of Endeavour Energy's metering assets. Rather than accepting its proposal for 5 year accelerated depreciation, we maintain our draft decision.¹⁰⁵ This provides for a standard asset life of 15 years and a remaining asset life for existing metering assets of 23 years.
- In support of its proposal for accelerated depreciation, Endeavour Energy stated that its approach would assist in minimising the risk of stranded assets following the opening up of competition in metering.¹⁰⁶ We do not, however, accept that this risk is significant enough to warrant the proposed asset lives. Our view is that it is unlikely that all of Endeavour Energy's meters will be provided by alternative providers within 5 years. It would therefore not be an efficient outcome for all existing and replacement meters to be depreciated by the end of the 2015–19 regulatory control period. Instead, we specify asset lives which are reflective of the expected technical usefulness of the meters.

Forecast capex

We accept Endeavour Energy's proposed \$14.6 million (\$2014–15) in capex. This final decision is based on our assessment of Endeavour Energy's unit costs and revised forecast volumes. We also note Endeavour Energy's revised capex is a 21 percent reduction from its initial proposal for \$18.5 million (\$2014–15).¹⁰⁷

Unit costs

Our final decision is to accept Endeavour Energy's proposed material and non-material unit costs. This is because:

- the proposed material unit costs are either within the observed market range or only marginally higher such that any adjustment would be immaterial
- the proposed non-material unit costs are, as we found in our draft decision, reasonable.

¹⁰⁴ Endeavour Energy, *Revised regulatory proposal*, January 2015, p. 243.

¹⁰⁵ AER, *Draft decision on Endeavour Energy's distribution determination*, November 2014, p. 16–14 to 45.

¹⁰⁶ Endeavour Energy, *Revised regulatory proposal*, January 2015, p. 243.

¹⁰⁷ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 238.

At the draft decision stage, we engaged Marsden Jacob to assist us in assessing Endeavour Energy's forecast material unit costs. In providing its advice, the consultant considered the 'maximum rate that should be applied for each meter hardware category based on consideration of the rates applied across the business and a comparison against current market rates'.¹⁰⁸ These rates were sourced from online advertised prices and through direct engagement with major suppliers.¹⁰⁹ Marsden Jacob took into consideration volume discounts which would reasonably be expected to apply to metering hardware purchases made by Endeavour Energy.¹¹⁰

Using Marsden Jacob's findings, we observed that Endeavour Energy's material unit costs are within the range of current market rates for metering hardware.¹¹¹ Table 16.13 sets out Endeavour Energy's forecast material unit costs and Marsden Jacob's observations on current market rates.

Table 16.13 Endeavour Energy's forecast material unit costs, Marsden Jacobs's observed market rates, and our substitute forecast (\$ 2014–15)

Description	Forecast	Markets rates	Final decision
Type 6			
Single phase accumulation meter	18.69	18.69–20.00	Accept
Single phase accumulation combination meter	153.73	Insufficient information	Accept
Three phase accumulation meter	88.51	86.50–100.00	Accept

Source: Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, p. 33.

We accept Endeavour Energy's proposed material unit costs. In each instance where Marsden Jacob was able to obtain sufficient information, the proposed unit costs were at the bottom end of, or marginally above, the current market rates.

Forecast volumes

We maintain our draft decision accepting Endeavour Energy's forecast volumes of new or upgraded connections and reactive replacements. Our final decision also accepts Endeavour Energy's revised proactive replacement forecast. Table 16.14 sets out the

¹⁰⁸ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

¹⁰⁹ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

¹¹⁰ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

¹¹¹ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

initial and revised forecast volumes for annual metering services, together with our draft and final decisions.

Table 16.14 Forecast volumes for annual metering services

	Initial proposal	Revised proposal	Draft decision	Final decision
New/upgraded connections (2014-15 only)	22 234	22 234	22 234	22 234
Reactive replacements	17 471	17 417	17 471	17 471
Proactive replacements	130 077	80 792	21 406	80 792

Source: Endeavour Energy, *NSW ACT Electricity DNSPs reset RIN templates - Consolidated information (Public)*, May 2014; Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 237–238.

Our draft decision did not accept Endeavour Energy's forecast volume of proactive replacements. Proactive replacements are driven by regulatory obligations under the NER and Australian Standards. They set out procedures for testing if a population of meters are measuring energy usage accurately. Because it would be inefficient to test every meter in service, Australian Standard 1284.13 specifies the number of meters which need to be tested before it can be statistically determined if the whole population is accurately measuring energy usage. We did not accept Endeavour Energy's initially proposed proactive replacement forecast because we were not provided with evidence showing that accuracy tests had actually been conducted.¹¹²

In response to our draft decision, Endeavour Energy revised its proactive replacement forecast from 130 077 to 80 792 meters.¹¹³ It also provided additional evidence supporting the revised forecast.¹¹⁴ This included updated information from its metering asset management plan and data on meters which have failed accuracy tests conducted by other Networks NSW businesses. A total of 78 376 meters forecast for replacement relate to such tests conducted by Essential Energy and Ausgrid, rather than Endeavour Energy itself.

We accept the revised proactive replacement volumes. In the absence of Endeavour Energy conducting tests on the accuracy of its meters, it is sufficient for it to rely on the data other Networks NSW businesses have collected. This is because the tests relate to the same meters, in terms of their make and model, which Endeavour Energy has in service.¹¹⁵ Our final decision therefore approves the revised proactive replacement

¹¹² AER, *Draft decision: Endeavour Energy: Distribution determination 2014–15 and 2015–19*, November 2014, p. 40.

¹¹³ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 236–7.

¹¹⁴ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 236–7.

¹¹⁵ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 236.

because it is supported by actual data on tests performed against compliance obligations.

Forecast opex

We accept \$71.7 million in opex for annual metering services and substitute that amount for Endeavour Energy's proposed \$108.9 million (\$2014–15). This is equal to about 66 percent of the Endeavour Energy's total proposed opex.

Base

To assess this, we observed Endeavour Energy's opex over a five year period (2008–09 to 2012–13). This is the same approach we applied in the draft decision. Endeavour Energy also accepted this multi-year approach to determining base opex.¹¹⁶

Our data source for historic metering opex was from the economic benchmarking RINs. This data is inclusive of overheads and so we did not have to further apply overheads. This is different to Endeavour Energy's approach which used direct costs to begin with and then applied overheads.¹¹⁷

Consistent with our approach for standard control services, we further examined the proposed base from another perspective by applying benchmarking.

For the final decision, we applied base adjustments to all distributors' historic metering opex data to remove ancillary metering costs before performing our benchmarking analysis. Thus, our benchmarking analysis for the final decision more accurately compares default metering opex only.

Endeavour Energy proposed to remove \$649,823 (\$ 2014–15) in ancillary metering costs over the 2008–09 to 2012–13 period. Their calculation was based on work orders for special meter reading and meter accuracy tests extracted from the audited working files for the 2012/13 Reset RIN.¹¹⁸ In comparison, we used data from the final audited Reset RINs. Our calculation arrived at a considerably higher amount of \$22.9 million (\$ 2014–15).

Endeavour Energy explained the difference is that their calculation is based on individual work orders that did not include overheads and therefore 'did not capture all of the costs involved' while 'RIN data was based on an estimate of what we considered the true, full cost to be for this ANS [ancillary network service]'.¹¹⁹ Another difference is that our calculation included 'move in/out reads' which will also be recovered through ancillary network services, while Endeavour Energy's proposed amount did not.

¹¹⁶ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 240.

¹¹⁷ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 240.

¹¹⁸ Endeavour Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019, Attachment 8.04 Revised Metering Model and Price List*, January 2015.

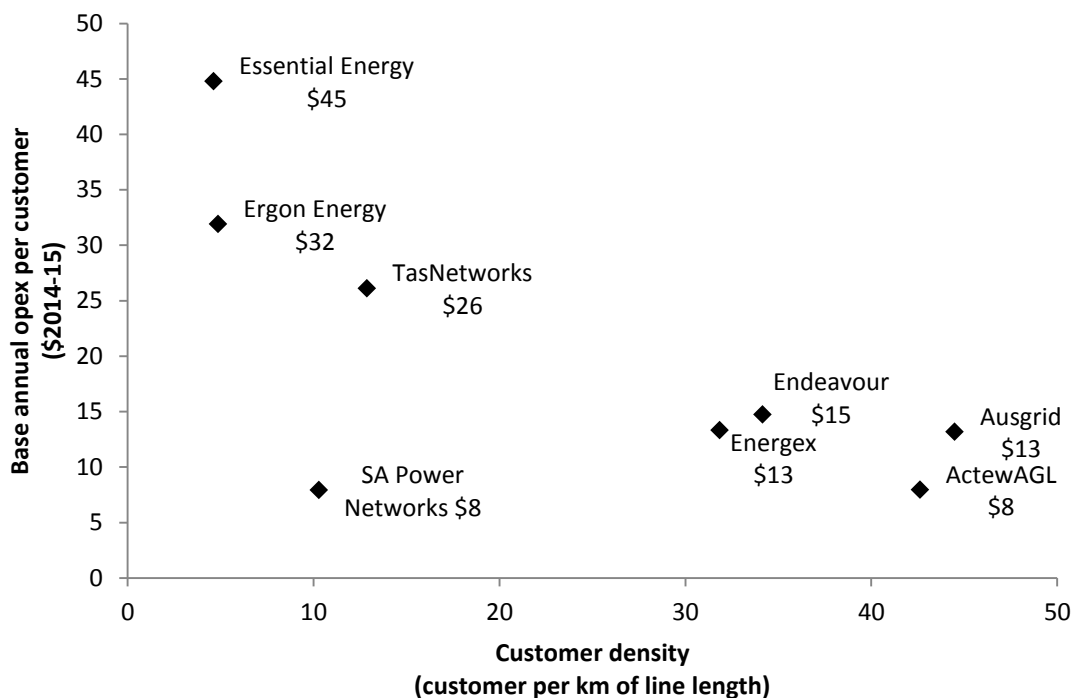
¹¹⁹ Endeavour Energy, email RE: Meeting to discuss metering opex step changes, attachment 'Metering ANS reconciliation', 24 March 2015.

Our metering opex analysis is inclusive of overheads and so we applied our calculation for ancillary metering service costs to make the base adjustment, rather than Endeavour Energy's proposed adjustment which was based on direct costs only.

We used a partial performance indicator as our benchmarking method which compared Endeavour Energy's proposed opex per customer against other non-Victorian distribution businesses in the national electricity market.

When comparing Endeavour 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 16.6 shows the results of our benchmarking.

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



Source: AER analysis

Endeavour Energy objected to us assuming a linear relationship to chart the frontier 'which is contrary to the AER's application of benchmarking in its Annual Benchmarking Report'.¹²⁰ We recognise that our inclusion of a trend line in Figure 16-5 of our draft decision may have given the impression that we were assuming a linear

¹²⁰ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 239.

relationship. However, our benchmarking analysis does not rely on there being a perfect linear relationship. What we do observe is a strong correlation between customer density and costs, and so we can reasonably expect Endeavour Energy to require no more opex per customer than a distribution business with a similarly dense network.

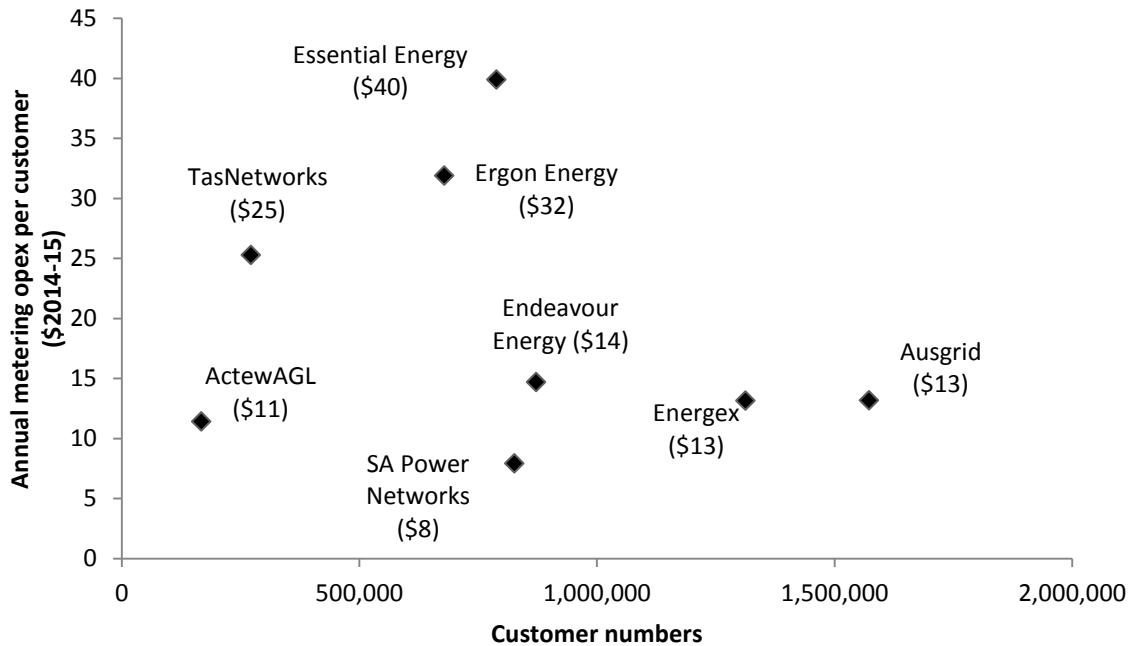
Specifically, we consider Energex to be a relevant comparator for Endeavour Energy because the Queensland distribution business has a similar (in fact, lower) customer density. However, on a per customer basis we observed that Endeavour Energy's proposed opex is more than Energex's reported opex. In the 2014–15 and 2015–19 regulatory control periods, Endeavour Energy proposes to spend \$15 per customer. Energex, however, spent \$13 per customer. Further we would expect, if anything, for Energex to have a higher per customer metering opex than Endeavour Energy. This is because Energex has a less dense network.

We reached the same conclusion, using similar analysis, in our draft decision. This led to use not accepting Endeavour Energy's proposed opex and substituting it with an amount equal to Energex's per customer spend. In response, Endeavour Energy's revised regulatory proposal objected to our use of Energex as its comparator for the purpose of benchmarking. This was on the basis that:¹²¹

- the number of customers that Energex services enables economies of scale that Endeavour Energy cannot access with its metering services
- there are cost of living differences between QLD and NSW that will impact the labour rates for Energex and Endeavour Energy
- on a direct costs basis Endeavour Energy compares favourably to Energex which appears to have only allocated a small proportion of overheads to metering
- customer density is not the sole driver of metering costs and other organisational and environmental differences exist between Energex and Endeavour Energy that are not account for.
- We considered if we should adjust our benchmarking approach to account for any of these factors. To do this, we assessed the likely effect they have on our benchmarking results. We consider that none of the factors raised in Endeavour Energy's revised proposal would materially affect our results to the extent that we should depart from our assessment approach.
- We do not consider differences in economies of scale to be a factor which would materially affect our benchmarking results. Figure 16.7 shows that there appears to be no correlation between annual metering opex per customer and customer numbers.

¹²¹ Endeavour Energy, *Revised regulatory proposal*, November 2014, p. 239.

Figure 16.7 – Annual metering opex per customer and customer numbers



Source: AER analysis

For example, Ausgrid has a large number of customers and ActewAGL relatively few. If economies of scale do have a material impact on operating costs, then we would expect Ausgrid's higher customer base to lead to efficiencies. However, both Ausgrid and ActewAGL perform about the same when their opex are benchmarked. In fact, ActewAGL has a lower opex per customer. We therefore have decided against adjusting for any efficiency gains (or losses) resulting from higher (or lower) economies of scale.

In relation to cost of living differences, we consider that this factor may be relevant if any differences in costs of living have flow on effects to the hourly rates paid to workers. To determine if this is the case, we compared Endeavour Energy's labour rates to the business which we consider to be its efficient comparator (Energex). We observed that even if New South Wales has a higher cost of living than Queensland, as Endeavour Energy claimed in its revised regulatory proposed, this is not reflected in the respective labour rates.

Using analysis conducted by our consultant Marsden Jacob, we found that Energex pays its technicians more than Endeavour Energy.¹²² We consider this to be significant. The higher pay of Energex workers shows that any cost of living differences between Queensland and New South Wales is not driving Endeavour Energy's higher opex. We

¹²² Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 1.1.1. Table 1 (confidential).

consider that this is not a factor for which our benchmarking results should be adjusted.

With regard to Endeavour Energy's contention that it compares favourably to Energex on a direct cost basis, our position is that we do not adjust for differences in cost allocation methods. We took this approach in our draft decision on Endeavour Energy's opex for standard control services (SCS).¹²³ Our reasoning is that the cost allocation method a business chooses reflects what it considers to be an efficient corporate structure.¹²⁴ We have also observed that businesses of varying cost allocation methods are capable of being at the frontier of efficiency.¹²⁵ This has in turn led us to conclude that 'cost allocation may affect benchmarking but not significantly'.¹²⁶ Refer to attachment 7 of our draft decision on Endeavour Energy's SCS opex for further information about our position.

In response to Endeavour Energy's point regarding why there was a difference between the adjustments made to SCS opex and metering opex, we conducted separate analysis. In this instance we are considering a different set of costs and conduct analysis based on those costs. And given that it is the same business and same labour force, we would expect that the general direction would be the same, but that does not mean any substitute forecasts would be proportionate.

Endeavour Energy's revised regulatory proposal noted that customer density is not the sole driver of operating costs. We stated that this may be the case in our draft decision. We also invited Endeavour Energy to suggest factors which should be accounted for in our benchmarking results given that they are exogenous.¹²⁷ We have considered each of those suggested factors, but find that none of them are in fact exogenous and thereby we have maintained our draft decision approach. That is, our benchmarking approach has only accounted for differences in customer density.

Our evaluation of Endeavour Energy's base leads us to accept less opex than proposed. Driving our substitute base is our application of an efficiency adjustment to bring Endeavour Energy's opex in to line with a distribution business (Energex) with similar network characteristics. To reach this point, we considered whether we should account for any other exogenous factors, besides customer density. We considered the factors suggested in Endeavour Energy's regulatory proposal,¹²⁸ but concluded that none of them should be taken into account for reasons set out above.

Step changes

¹²³ AER, *Draft decision: Endeavour Energy: Distribution determination 2014–15 and 2015–19*, November 2014, p. 7–46.

¹²⁴ AER, *Draft decision: Endeavour Energy: Distribution determination 2014–15 and 2015–19*, November 2014, p. 7–46.

¹²⁵ AER, *Draft decision: Endeavour Energy: Distribution determination 2014–15 and 2015–19*, November 2014, p. 7–46.

¹²⁶ AER, *Draft decision: Endeavour Energy: Distribution determination 2014–15 and 2015–19*, November 2014, p. 7–46.

¹²⁷ Endeavour Energy, *Revised regulatory proposal*, November 2014, p. 239.

¹²⁸ Endeavour Energy, *Revised regulatory proposal*, November 2014, p. 239.

In our draft decision, we stated that Endeavour Energy should apply a negative step change to account for ancillary metering services being charged upfront from 1 July 2015.¹²⁹ Specifically, a customer who requests certain metering services, such as a special meter read, will be charged an ancillary network service fee in the 2015–19 regulatory control period and hence these costs should not form part of our opex assessment for default Type 5 and 6 metering services.

In its revised proposal, Endeavour Energy noted that no reduction is required because it already removed these costs from the base opex.¹³⁰ We agree with this approach. Ancillary metering costs should be removed from the base (historic expenditure) rather than applied as a step change. We have therefore applied base adjustments to all distributors' historic metering opex data to remove ancillary metering costs to refine our benchmarking analysis. This is so it more accurately compares only historic opex for default metering.

Therefore, for our final decision, we did not apply a negative step change for ancillary metering services as we accounted for this through making a base adjustment instead.

We accept Endeavour Energy's proposed positive step changes for the adoption of the NECF and asbestos management compliance obligations. We are satisfied that they are new regulatory obligations which will lead to higher operating costs, not captured in each year of the 2008–09 to 2012–13 data we used for our base analysis.

However, we made adjustments to the proposed step change amounts. Endeavour Energy proposed step change amounts based on historic direct costs. Instead, to be consistent with how we made our base adjustment for ancillary metering costs, we approve larger step change amounts that include both direct and overhead costs.

Trend

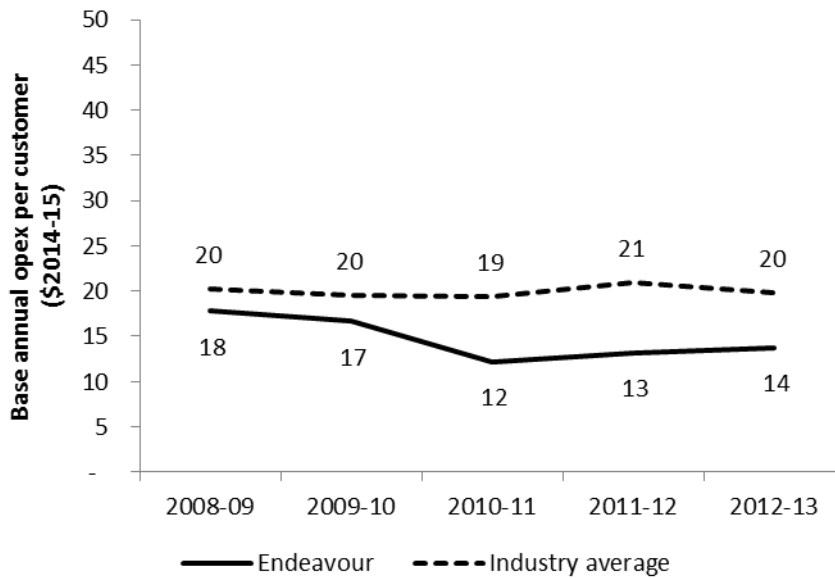
We trended the base forward for forecast metering customer growth. Consistent with our draft decision, we have applied zero forecast real price and productivity growth.

Our analysis for base metering opex used average data from 2008–09 to 2012–13. We looked at the annual data as well. Figure 16.8 shows that over 2008–09 to 2012–13, Endeavour Energy's metering opex per customer did not increase. This is consistent with the industry average. This implies that either there were no real price increases over this period, or the distributors were able to offset these real price increases with productivity improvements.

¹²⁹ AER, *Draft decision: Endeavour Energy: Distribution determination 2014–15 and 2015–19*, November 2014, p. 16–65.

¹³⁰ Endeavour Energy, *Revised Regulatory Proposal 1 July 2015 to 30 June 2019*, January 2015, p. 240.

Figure 16.8 – Annual default metering opex per customer



Source: AER analysis

Given that opex is largely recurrent and metering opex per customer did not increase over the 2008–09 to 2012–13 period, we do not forecast metering opex per customer to increase in the 2015–19 regulatory control period. Therefore, we do not approve Endeavour Energy's proposal to apply real price growth (labour escalators). Instead, we apply zero real price and productivity growth.

Our substitute \$71.7 million is less than the \$108.9 million (\$2014–15) Endeavour Energy proposed. However, we consider it to better reflect an efficient distribution business' likely future requirements. This is because, compared to Endeavour Energy, we applied a more comprehensive forecasting methodology which included the use of benchmarking.

16.3.5.3 Upfront capital charges

We accept Endeavour Energy's proposal that all new meters for growth or replacement initiated by a customer be recovered upfront from customers.¹³¹ Additionally, we accept all of Endeavour Energy's proposed price caps for new or upgraded connections.

For new or upgraded connections, we were required to assess the material unit costs for both Type 5 and 6 meters. This is a broader assessment than we applied in relation to Endeavour Energy's proposed annual metering services charge, where we only considered the unit costs of meters with a Type 6 classification (see section 16.3.5.2 above). The reason for this is that the annual metering service charge recovers the capital cost of replacing existing installations with Type 6 hardware. By contrast,

¹³¹ Endeavour Energy, *Revised regulatory proposal*, November 2014, p. 241.

Endeavour Energy wishes to offer both Type 5 and 6 metering options to customers seeking a new or upgraded connection.

Notwithstanding the broader assessment, we applied the same approach to our review of Endeavour Energy's proposed material unit costs for new or upgraded connections, as we applied to the annual metering service charge. In particular, we considered the proposed Type 5 and 6 material unit costs against the market rates our consultant, Marsden Jacob, observed. Table 16.15 sets out our assessment based on those market rates, for both type 5 and 6 meters.

Table 16.15 – Endeavour Energy's forecast material unit costs, Marsden Jacobs's observed market rates, and our substitute forecast (\$ 2014–15)

Description	Forecast	Markets rates	Final decision
Type 6			
Single phase accumulation meter	18.69	18.69–20.00	Accept
Single phase accumulation combination meter	153.73	Insufficient information	Accept
Three phase accumulation meter	88.51	86.50–100.00	Accept
Type 5			
Single phase interval (TOU capable) meter	61.10	63.72 – 100.00	Accept
Single phase interval (TOU capable) combination meter	149.00	126.00 – 150.00	Accept
Three phase interval (TOU capable) meter	328.98	Insufficient information	Accept

Source: Marsden Jacob, *Consultant report to the AER on Alternative Control Services*, October 2014, p. 33; Endeavour Energy, *Revised regulatory proposal, Attachment 8.04: Revised metering model and price list*, January 2015.

All of Endeavour Energy's proposed material unit costs are within our consultant's observed market ranges. We have therefore accepted them.

We considered whether the upfront capital charges should be annually adjusted for labour price changes. Our final decision is that no such adjustment should take place. The approved upfront capital charges are mostly made up of material costs, with only a small labour component. We therefore do not consider an annual adjustment for changes in labour prices to be reasonably required.

Appendix A contains the approved prices for new and upgraded connections.

16.3.5.4 Meter transfer fee

We do not approve a meter transfer fee for Endeavour Energy. 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' revised 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.¹³²

Our New South Wales and Australian Capital Territory draft decisions sought further information from distributors and the market about the veracity of meter transfer fees. As noted by Endeavour Energy in its revised proposal, we did not accept our consultant Marsden Jacob's recommendation of a benchmark meter transfer fee. This is because since that report, we have further consulted with stakeholders and gathered significant more information which we have incorporated into our analysis.

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.¹³³

Oakley Greenwood, in its report to Origin Energy corroborated stakeholders view's 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.¹³⁴

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.¹³⁵ The retailer considered that a consistent approach to the calculation of administrative costs was most appropriate.¹³⁶

¹³² 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.

¹³³ 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.

¹³⁴ 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).

¹³⁵ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 1) p. 36.

¹³⁶ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 2), p. 7.

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.¹³⁷

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.¹³⁸ 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.¹³⁹ 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.¹⁴⁰

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

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

¹³⁷ Meeting between respective staff of Simply Energy and AER on 16 March 2015.

¹³⁸ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

¹³⁹ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

¹⁴⁰ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

This is confirmed by the Australian Energy Market Operator who has a new set of meter churn procedures due to commence September 2015.¹⁴¹ 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.¹⁴² 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
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

¹⁴¹ 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.

¹⁴² 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.

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.¹⁴³ 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.¹⁴⁴

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 \$64.91 (\$2014–15)¹⁴⁵ could amount to a de-facto exit fee that would act as a barrier to competition and the uptake of new advanced meters. While the national electricity law requires us to ensure distributors have the opportunity to recover at least their efficient costs we are not persuaded by the evidence that distributors have material incremental costs to recover in amending records to take account of customer churn. Any incremental costs will be borne by the acquirer of the new meter customer—at the moment, retailers. Furthermore it is noteworthy that distributors are churning type 6 meters for interval meters for customers installing Solar Photovoltaic systems in large numbers without imposing any administrative fees for the meter transfer.

¹⁴³ Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

¹⁴⁴ Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

¹⁴⁵ Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 235.

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 final decision will see Endeavour Energy recover \$13 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 equal or greater than this is reasonable.¹⁴⁶

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

16.3.5.5 Control mechanism

Our draft decision included zero X-factors for both metering services (the annual charge and the upfront capital charge). We have amended this for our final decision.

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

We did consider whether X-factors for the upfront capital charges should include real price escalators. We do not consider any real labour escalators need apply as there is no labour component to the upfront capital charge. Consistent with our approach in opex and ancillary network services, we do not apply any real materials escalators as materials are forecast to grow no more than CPI.

¹⁴⁶ This logic also applies if we take Endeavour Energy's proposed average annual metering opex per customer \$22.

A Appendix

A.1 Ancillary network services

Table 16.17 Ancillary network services – Final decision

Fee Category	Driver	Fee Type	Proposed prices (\$2014-15)	AER final decision (\$2014-15)	Difference (per cent)
Administration fee					
Subdivision - URD - Underground - 1-5 lots	Per Job	Fee	690.39	356.24	-48.4
Subdivision - URD - Underground - 6-10 lots	Per Job	Fee	862.99	445.3	-48.4
Subdivision - URD - Underground - 11-40 lots	Per Job	Fee	1,208.18	623.42	-48.4
Subdivision - URD - Underground - 41+ lots	Per Job	Fee	1,380.78	712.48	-48.4
Subdivision - Non Urban - Underground - 1-5 lots	Per Job	Fee	517.79	267.18	-48.4
Subdivision - Non Urban - Underground - 6-10 lots	Per Job	Fee	690.39	356.24	-48.4
Subdivision - Non Urban - Underground - 11-40 lots	Per Job	Fee	862.99	445.3	-48.4
Subdivision - Non Urban - Underground - 41+ lots	Per Job	Fee	1,035.58	534.36	-48.4

Subdivision - Non Urban - Overhead - 1-5 poles	Per Job	Fee	690.39	356.24	-48.4
Subdivision - Non Urban - Overhead - 6-10 poles	Per Job	Fee	862.99	445.3	-48.4
Subdivision - Non Urban - Overhead - 11+ poles	Per Job	Fee	1,553.38	801.54	-48.4
Subdivision - Industrial & Commercial - Per Hour	Per Hour	Quote	172.60	89.06	-48.4
Connection of Load - URD - Per Hour	Per Hour	Quote	172.60	89.06	-48.4
Connection of Load - Industrial & Commercial - Per Hour	Per Hour	Quote	172.60	89.06	-48.4
Connection of Load - Non Urban - Underground - Per Hour	Per Hour	Quote	172.60	89.06	-48.4
Connection of Load - Non Urban - Overhead - 1-5 poles	Per Job	Fee	690.39	356.24	-48.4
Connection of Load - Non Urban - Overhead - 6-10 poles	Per Job	Fee	1035.58	534.36	-48.4
Connection of Load - Non Urban - Overhead - 11+ poles	Per Job	Fee	1380.78	712.48	-48.4
Other - Asset Relocation - Per Hour	Per Hour	Quote	172.60	89.06	-48.4
Other - Public Lighting - Per	Per Hour	Quote	172.60	89.06	-48.4

Hour

Design information fee

Subdivision - URD - Underground - 1-5 lots	Per Job	Fee	639.22	428.43	-33.0
Subdivision - URD - Underground - 6-10 lots	Per Job	Fee	852.30	571.24	-33.0
Subdivision - URD - Underground - 11-40 lots	Per Job	Fee	1491.52	999.66	-33.0
Subdivision - URD - Underground - 41+ lots	Per Job	Fee	1917.67	1285.28	-33.0
Subdivision - Non Urban - Per Hour	Per Hour	Quote	213.07	142.81	-33.0
Subdivision - Industrial & Commercial - Per Hour	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Industrial & Commercial - <= 200A/Phase (LV)	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Industrial & Commercial - <= 700A/Phase (LV)	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Industrial & Commercial - > 700A/Phase (LV)	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Industrial & Commercial - HV Customer	Per Hour	Quote	213.07	142.81	-33.0

Connection of Load - Industrial & Commercial - Transmission	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Multi-Dwelling - <= 5 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Multi-Dwelling - <= 20 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Multi-Dwelling - <= 40 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Multi-Dwelling - > 40 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - I&C - <= 200A/Phase (LV)	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - I&C - <= 700A/Phase (LV)	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - I&C - > 700A/Phase (LV)	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - I&C - HV Customer	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - I&C - Transmission	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - Multi-Dwelling - <= 5 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - Multi-Dwelling - <= 20	Per Hour	Quote	213.07	142.81	-33.0

units					
Connection of Load - Non Urban - Multi-Dwelling - <= 40 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - Multi-Dwelling - > 40 units	Per Hour	Quote	213.07	142.81	-33.0
Connection of Load - Non Urban - Single Residential - Per Hour	Per Hour	Quote	213.07	142.81	-33.0
Asset Relocation - Engineer					
Asset Relocation - Engineer	Per Hour	Quote	213.07	142.81	-33.0
Asset Relocation - Designer					
Asset Relocation - Designer	Per Hour	Quote	213.07	142.81	-33.0
Public Lighting - Engineer					
Public Lighting - Engineer	Per Hour	Quote	213.07	142.81	-33.0
Public Lighting - Designer					
Public Lighting - Designer	Per Hour	Quote	213.07	142.81	-33.0
Design certification fee					
Subdivision - URD - Underground - 1-5 lots	Per Job	Fee	437.16	285.62	-34.7
Subdivision - URD - Underground - 6-10 lots	Per Job	Fee	655.74	428.43	-34.7
Subdivision - URD - Underground - 11-40 lots	Per Job	Fee	1092.90	714.04	-34.7
Subdivision - URD - Underground - 41+ lots	Per Job	Fee	1311.48	856.85	-34.7

Subdivision - Non Urban - Underground - 1-5 lots	Per Job	Fee	218.58	142.81	-34.7
Subdivision - Non Urban - Underground - 6-10 lots	Per Job	Fee	655.74	428.43	-34.7
Subdivision - Non Urban - Underground - 11-40 lots	Per Job	Fee	874.32	571.24	-34.7
Subdivision - Non Urban - Underground - 41+ lots	Per Job	Fee	874.32	571.24	-34.7
Subdivision - Non Urban - Overhead - 1-5 poles	Per Job	Fee	437.16	285.62	-34.7
Subdivision - Non Urban - Overhead - 6-10 poles	Per Job	Fee	655.74	428.43	-34.7
Subdivision - Non Urban - Overhead - 11+ poles	Per Job	Fee	1092.90	714.04	-34.7
Subdivision - Industrial & Commercial - Underground - 1-10 lots	Per Job	Fee	655.74	428.43	-34.7
Subdivision - Industrial & Commercial - Underground - 11-40 lots	Per Job	Fee	874.32	571.24	-34.7
Subdivision - Industrial & Commercial - Underground - 41 + lots	Per Job	Fee	1311.48	856.85	-34.7
Subdivision - Industrial & Commercial - Overhead - 1-5 poles	Per Job	Fee	437.16	285.62	-34.7
Subdivision - Industrial & Commercial - Overhead - 6-10	Per Job	Fee	655.74	428.43	-34.7

poles						
Subdivision - Industrial & Commercial - Overhead - 11+ poles	Per Job	Fee	1092.90	714.04	-34.7	
Connection of Load - Industrial & Commercial - <= 200A/Phase (LV)						
Connection of Load - Industrial & Commercial - <= 200A/Phase (LV)	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Industrial & Commercial - <= 700A/Phase (LV)						
Connection of Load - Industrial & Commercial - <= 700A/Phase (LV)	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Industrial & Commercial - > 700A/Phase (LV)						
Connection of Load - Industrial & Commercial - > 700A/Phase (LV)	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Industrial & Commercial - HV Customer						
Connection of Load - Industrial & Commercial - HV Customer	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Industrial & Commercial - Transmission						
Connection of Load - Industrial & Commercial - Transmission	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Multi-Dwelling - <= 5 units						
Connection of Load - Multi-Dwelling - <= 5 units	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Multi-Dwelling - <= 20 units						
Connection of Load - Multi-Dwelling - <= 20 units	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Multi-Dwelling - <= 40 units						
Connection of Load - Multi-Dwelling - <= 40 units	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Multi-Dwelling - > 40 units						
Connection of Load - Multi-Dwelling - > 40 units	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Non Urban - Underground - Per						
Connection of Load - Non Urban - Underground - Per	Per Hour	Quote	218.58	142.81	-34.7	

Hour						
Connection of Load - Non Urban - Overhead - 1-5 poles	Per Job	Fee	437.16	285.62	-34.7	
Connection of Load - Non Urban - Overhead - 6-10 poles	Per Job	Fee	655.74	428.43	-34.7	
Connection of Load - Non Urban - Overhead - 11+ poles	Per Job	Fee	1092.90	714.04	-34.7	
Connection of Load - Indoor Substation - Per Hour	Per Job	Fee	218.58	142.81	-34.7	
Asset Relocation - Engineer						
Asset Relocation - Engineer	Per Hour	Quote	218.58	142.81	-34.7	
Asset Relocation - Designer						
Asset Relocation - Designer	Per Hour	Quote	218.58	142.81	-34.7	
Public Lighting - Engineer						
Public Lighting - Engineer	Per Hour	Quote	218.58	142.81	-34.7	
Public Lighting - Designer						
Public Lighting - Designer	Per Hour	Quote	218.58	142.81	-34.7	
Design re-certification fee						
Subdivision - Industrial & Commercial - Per Hour						
Subdivision - Industrial & Commercial - Per Hour	Per Hour	Quote	218.58	142.81	-34.7	
Subdivision - Non Urban - Per Hour						
Subdivision - Non Urban - Per Hour	Per Hour	Quote	218.58	142.81	-34.7	
Subdivision - URD - Per Hour						
Subdivision - URD - Per Hour	Per Hour	Quote	218.58	142.81	-34.7	
Connection of Load - Industrial & Commercial - Per Hour						
Connection of Load - Industrial & Commercial - Per Hour	Per Hour	Quote	218.58	142.81	-34.7	

Connection of Load - Non Urban - Per Hour	Per Hour	Quote	218.58	142.81	-34.7
Connection of Load - URD - Per Hour	Per Hour	Quote	218.58	142.81	-34.7
Asset Relocation - Engineer	Per Hour	Quote	218.58	142.81	-34.7
Asset Relocation - Designer	Per Hour	Quote	218.58	142.81	-34.7
Public Lighting - Engineer	Per Hour	Quote	218.58	142.81	-34.7
Public Lighting - Designer	Per Hour	Quote	218.58	142.81	-34.7
Notification of arrangement					
Subdivision - Industrial & Commercial - Per NOA	Per Job	Fee	375.94	178.12	-52.6
Subdivision - Non Urban - Per NOA	Per Job	Fee	375.94	178.12	-52.6
Subdivision - URD - Per NOA	Per Job	Fee	375.94	178.12	-52.6
Subdivision - Industrial & Commercial - Per hour for early notification	Per Hour	Quote	187.97	89.06	-52.6
Subdivision - Non Urban - Per hour for early notification	Per Hour	Quote	187.97	89.06	-52.6
Subdivision - URD - Per hour for early notification	Per Hour	Quote	187.97	89.06	-52.6

Compliance certificate

Connection of Load - Industrial & Commercial - Per Compliance Cert	Per Job	Fee	375.94	178.12	-52.6
Connection of Load - Non Urban - Per Compliance Cert	Per Job	Fee	563.91	267.18	-52.6
Connection of Load - URD - Per Compliance Cert	Per Job	Fee	375.94	178.12	-52.6
Connection of Load - Industrial & Commercial - Per hour for early cert	Per Hour	Quote	187.97	89.06	-52.6
Connection of Load - Non Urban - Per hour for early cert	Per Hour	Quote	187.97	89.06	-52.6
Connection of Load - URD - Per hour for early cert	Per Hour	Quote	187.97	89.06	-52.6
Inspection of service work (level 1)					
Subdivision - URD - Underground - Per Lot (1 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Subdivision - URD - Underground - Per Lot (11 - 50) - Grade A	Per Job	Fee	60.77	42.84	-29.5
Subdivision - URD - Underground - Per Lot (51 +) - Grade A	Per Job	Fee	20.26	14.28	-29.5

Subdivision - URD - Underground - Per Lot (1 - 10) - Grade B	Per Job	Fee	232.97	164.23	-29.5
Subdivision - URD - Underground - Per Lot (11 - 50) - Grade B	Per Job	Fee	141.81	99.97	-29.5
Subdivision - URD - Underground - Per Lot (51 +) - Grade B	Per Job	Fee	81.03	57.12	-29.5
Subdivision - URD - Underground - Per Lot (1 - 10) - Grade C	Per Job	Fee	506.45	357.03	-29.5
Subdivision - URD - Underground - Per Lot (11 - 50) - Grade C	Per Job	Fee	283.61	199.93	-29.5
Subdivision - URD - Underground - Per Lot (51 +) - Grade C	Per Job	Fee	131.68	92.83	-29.5
Subdivision - URD - Underground - Per Hour + \$44 travel time	Per Hour	Quote	202.58	142.81	-29.5
Subdivision - Non Urban - Underground - Per Lot (1 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Subdivision - Non Urban - Underground - Per Lot (11 - 50) - Grade A	Per Job	Fee	60.77	42.84	-29.5
Subdivision - Non Urban - Underground - Per Lot (51+) - Grade A	Per Job	Fee	20.26	14.28	-29.5

Subdivision - Non Urban - Underground - Per Lot (1 - 10) - Grade B	Per Job	Fee	243.10	171.37	-29.5
Subdivision - Non Urban - Underground - Per Lot (11 - 50) - Grade B	Per Job	Fee	131.68	92.83	-29.5
Subdivision - Non Urban - Underground - Per Lot (51+) - Grade B	Per Job	Fee	81.03	57.12	-29.5
Subdivision - Non Urban - Underground - Per Lot (1 - 10) - Grade C	Per Job	Fee	516.58	364.17	-29.5
Subdivision - Non Urban - Underground - Per Lot (11 - 50) - Grade C	Per Job	Fee	303.87	214.22	-29.5
Subdivision - Non Urban - Underground - Per Lot (51+) - Grade C	Per Job	Fee	141.81	99.97	-29.5
Subdivision - Non Urban - Overhead - Per Pole (1 - 5) - Grade A	Per Job	Fee	121.55	85.69	-29.5
Subdivision - Non Urban - Overhead - Per Pole (6 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Subdivision - Non Urban - Overhead - Per Pole (11 +) - Grade A	Per Job	Fee	81.03	57.12	-29.5
Subdivision - Non Urban - Overhead - Per Pole Sub - Grade A	Per Job	Fee	688.77	485.55	-29.5

Subdivision - Non Urban - Overhead - Per Pole (1 - 5) - Grade B	Per Job	Fee	243.10	171.37	-29.5
Subdivision - Non Urban - Overhead - Per Pole (6 - 10) - Grade B	Per Job	Fee	202.58	142.81	-29.5
Subdivision - Non Urban - Overhead - Per Pole (11 +) - Grade B	Per Job	Fee	131.68	92.83	-29.5
Subdivision - Non Urban - Overhead - Per Pole Sub - Grade B	Per Job	Fee	1418.07	999.67	-29.5
Subdivision - Non Urban - Overhead - Per Pole (1 - 5) - Grade C	Per Job	Fee	405.16	285.62	-29.5
Subdivision - Non Urban - Overhead - Per Pole (6 - 10) - Grade C	Per Job	Fee	374.77	264.20	-29.5
Subdivision - Non Urban - Overhead - Per Pole (11 +) - Grade C	Per Job	Fee	283.61	199.93	-29.5
Subdivision - Non Urban - Overhead - Per Pole Sub - Grade C	Per Job	Fee	1721.94	1213.89	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (1 - 5) - Grade A	Per Job	Fee	121.55	85.69	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (6 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5

Subdivision - Industrial & Commercial - Overhead - Per Pole (11 +) - Grade A	Per Job	Fee	81.03	57.12	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole Sub - Grade A	Per Job	Fee	709.03	499.84	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (1 - 5) - Grade B	Per Job	Fee	222.84	157.09	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (6 - 10) - Grade B	Per Job	Fee	202.58	142.81	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (11 +) - Grade B	Per Job	Fee	141.81	99.97	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole Sub - Grade B	Per Job	Fee	1418.07	999.67	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (1 - 5) - Grade C	Per Job	Fee	445.68	314.18	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (6 - 10) - Grade C	Per Job	Fee	403.14	284.19	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole (11 +) - Grade C	Per Job	Fee	303.87	214.22	-29.5
Subdivision - Industrial & Commercial - Overhead - Per Pole Sub - Grade C	Per Job	Fee	1782.71	1256.73	-29.5

Subdivision - Industrial & Commercial - Underground - Per Lot (1 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (11 - 50) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (51+) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (1 - 10) - Grade B	Per Job	Fee	243.10	171.37	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (11 - 50) - Grade B	Per Job	Fee	243.10	171.37	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (51+) - Grade B	Per Job	Fee	243.10	171.37	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (1 - 10) - Grade C	Per Job	Fee	506.45	357.03	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (11 - 50) - Grade C	Per Job	Fee	506.45	357.03	-29.5
Subdivision - Industrial & Commercial - Underground - Per Lot (51+) - Grade C	Per Job	Fee	506.45	357.03	-29.5
Connection of Load - URD -	Per Hour	Quote	202.58	142.81	-29.5

Underground - Per hour
(Inspector) + travel time

Connection of Load - URD - Underground - Per hour (Engineer) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Connection of Load - Non Urban - Underground - Per hour (Inspector) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Connection of Load - Non Urban - Underground - Per hour (Engineer) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (1 - 5) - Grade A	Per Job	Fee	121.55	85.69	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (1 - 5) - Grade B	Per Job	Fee	243.10	171.37	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (1 - 5) - Grade C	Per Job	Fee	445.68	314.18	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (6 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (6 - 10) - Grade B	Per Job	Fee	202.58	142.81	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (6 - 10) - Grade C	Per Job	Fee	403.14	284.19	-29.5
Connection of Load - Non	Per Job	Fee	81.03	57.12	-29.5

Urban - Overhead - Per Pole
(11 +) - Grade A

Connection of Load - Non Urban - Overhead - Per Pole (11 +) - Grade B	Per Job	Fee	141.81	99.97	-29.5
Connection of Load - Non Urban - Overhead - Per Pole (11 +) - Grade C	Per Job	Fee	303.87	214.22	-29.5
Connection of Load - Non Urban - Overhead - Per Pole Sub - Grade A	Per Job	Fee	688.77	485.55	-29.5
Connection of Load - Non Urban - Overhead - Per Pole Sub - Grade B	Per Job	Fee	1418.07	999.67	-29.5
Connection of Load - Non Urban - Overhead - Per Pole Sub - Grade C	Per Job	Fee	1721.94	1213.89	-29.5
Connection of Load - Industrial & Commercial - Underground - Per Hour (Inspector) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Connection of Load - Industrial & Commercial - Underground - Per Hour (Engineer) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (1 - 5) - Grade A	Per Job	Fee	121.55	85.69	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (1 - 5) - Grade B	Per Job	Fee	232.97	164.23	-29.5

Connection of Load - Industrial & Commercial - Overhead - Per Pole (1 - 5) - Grade C	Per Job	Fee	445.68	314.18	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (6 - 10) - Grade A	Per Job	Fee	101.29	71.41	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (6 - 10) - Grade B	Per Job	Fee	202.58	142.81	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (6 - 10) - Grade C	Per Job	Fee	403.14	284.19	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (11+) - Grade A	Per Job	Fee	81.03	57.12	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (11+) - Grade B	Per Job	Fee	141.81	99.97	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole (11+) - Grade C	Per Job	Fee	303.87	214.22	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole Sub - Grade A	Per Job	Fee	709.03	499.84	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole Sub - Grade B	Per Job	Fee	1418.07	999.67	-29.5
Connection of Load - Industrial & Commercial - Overhead - Per Pole Sub - Grade C	Per Job	Fee	1782.71	1256.73	-29.5

Asset Relocation - Asset Relocation - Underground - Per Hour (Inspector) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Asset Relocation - Asset Relocation - Underground - Per Hour (Engineer) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Public Lighting - Public Lighting - Underground - Per Hour (Inspector) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Public Lighting - Public Lighting - Underground - Per Hour (Engineer) + travel time	Per Hour	Quote	202.58	142.81	-29.5
Inspection of works outside normal working hours					
Administration Fee	Per Job	Fee	101.29	47.61	-53.0
Overtime Hours Rate	Per Hour	Quote	151.94	71.42	-53.0
Access Permits	Per AA or ATW	Fee	3590.14	2377.81	-33.8
Reinspection fee (level 1 & level 2 work)					
Reinspection Fee (Level 1 & Level 2 work)	Per Hour	Quote	192.58	142.81	-25.8

Inspection of service work (level 2 work)					
Per NOSW - A Grade	Per NOSW	Fee	65.22	49.98	-23.4
Per NOSW - B Grade	Per NOSW	Fee	111.81	85.69	-23.4
Per NOSW - C Grade	Per NOSW	Fee	372.71	285.62	-23.4
Provision of access fee (standby)					
Normal Time - 1 x Visit - Open / Close - 1 hour - Per Job	Per Job	Fee	150.30	143.06	-4.8
Normal Time - 1 x Visit - Open / Isolate & CSO to close - 1 hour - Per Job	Per Job	Fee	334.03	295.75	-11.5
Normal Time - 2 x Visit - Open / Close & no isolation - 2 hours - Per Job	Per Job	Fee	300.59	286.12	-4.8
Normal Time - 2 x Visit - Open / Isolate / Close - 2 hours - Per Job	Per Job	Fee	668.06	591.51	-11.5
Overtime - 1 x Visit - Open / Close - 1 hour - Per Job	Per Job	Fee	263.02	250.35	-4.8
Overtime - 1 x Visit - Open / Isolate & CSO to close - 1 hour - Per Job	Per Job	Fee	584.55	517.57	-11.5
Overtime - 2 x Visit - Open / Close & no isolation - 2 hours - Per Job	Per Job	Fee	526.04	500.71	-4.8

Overtime - 2 x Visit - Open / Isolate / Close - 2 hours - Per Job	Per Job	Fee	1169.11	1035.14	-11.5
Access permits					
Subdivision - URD - Per Lot	Per Lot	Fee	82.91	54.91	-33.8
All Other - Industrial & Commercial - Per access authorisation (AA) or authority to work (ATW)	Per AA or ATW	Fee	3590.14	2377.81	-33.8
All Other - Non Urban - Per access authorisation (AA) or authority to work (ATW)	Per AA or ATW	Fee	3590.14	2377.81	-33.8
All Other - URD - Per access authorisation (AA) or authority to work (ATW)	Per AA or ATW	Fee	3590.14	2377.81	-33.8
All Other - Asset Relocation - Per access authorisation (AA) or authority to work (ATW)	Per AA or ATW	Fee	3590.14	2377.81	-33.8
All Other - Public Lighting - Per access authorisation (AA) or authority to work (ATW)	Per AA or ATW	Fee	3590.14	2377.81	-33.8
Substation commission fee					
Subdivision - URD - Per Lot	Per Lot	Fee	77.10	57.53	-25.4
All Other - Industrial & Commercial - Per Substation	Per Substation	Fee	2235.95	1668.40	-25.4
All Other - Non Urban - Per	Per Substation	Fee	2235.95	1668.40	-25.4

Substation

All Other - URD - Per Substation	Per Substation	Fee	2235.95	1668.40	-25.4
All Other - Asset Relocation - Per Substation	Per Substation	Fee	2235.95	1668.40	-25.4
All Other - Public Lighting - Per Substation	Per Substation	Fee	2235.95	1668.40	-25.4

Excluded distribution services

Cost of excluded distribution services for interruption avoidance measures for contestable work planned electricity supply interruptions

Install & remove HV live line links - One set	Per Job	Fee	4674.53	4132.93	-11.6
Install & remove HV live line links - Each additional set	Per Job	Fee	2800.44	2644.92	-5.6
Break & remake HV bonds - One set	Per Job	Fee	3677.12	3204.71	-12.9
Break & remake HV bonds - Each additional set	Per Job	Fee	1878.65	1771.80	-5.7
Break & remake LV bonds - One set	Per Job	Fee	2343.32	1981.00	-15.5
Break & remake LV bonds - Each additional set	Per Job	Fee	1002.34	931.81	-7.0

Install & remove LV live line links - One set	Per Job	Fee	2308.60	1955.71	-15.3
Install & remove LV live line links - Each additional set	Per Job	Fee	967.62	906.51	-6.3
Connect & disconnect generator to LV OH mains - One generator	Per Job	Fee	2242.49	1907.55	-14.9
Connect & disconnect generator to LV OH mains - Each additional generator	Per Job	Fee	901.51	858.35	-4.8
Connect & disconnect generator to a padmount / indoor substation - One generator	Per Job	Fee	2242.49	1907.55	-14.9
Connect & disconnect generator to a padmount / indoor substation - Each additional gen	Per Job	Fee	901.51	858.35	-4.8
Cost of excluded distribution services to terminate cable at zone substations and first joint out from the zone substation					
Zone substation access and supervision for installation of cable(s) for one feeder	Per Job	Fee	3526.87	3061.65	-13.2
Protection setting	Per Job	Fee	5010.44	3984.69	-20.5
Testing cable prior to commissioning	Per Job	Fee	5357.04	4523.37	-15.6

11kV Zone substation circuit breaker cable termination	Per Job	Fee	4257.44	3593.88	-15.6
22kV Zone substation circuit breaker cable termination	Per Job	Fee	4428.70	3718.65	-16.0
11kV Padmount/Indoor substation cable termination	Per Job	Fee	4646.77	3877.52	-16.6
22kV Padmount/Indoor substation cable termination	Per Job	Fee	5712.44	4653.86	-18.5
11kV Pole top termination (UGOH) and bonding to OH	Per Job	Fee	5572.11	4551.63	-18.3
22kV Pole top termination (UGOH) and bonding to OH	Per Job	Fee	6284.18	5070.39	-19.3
11kV Straight through joint	Per Job	Fee	4568.70	3820.64	-16.4
22kV Straight through joint	Per Job	Fee	4786.02	3978.96	-16.9
Traffic Control					
Traffic Management to install & remove, break & remake, connect & disconnect excluded distribution services	Per Job	Fee	5121.86	3731.33	-27.2
Traffic Management to test, terminate and joint excluded distribution services	Per Job	Fee	4695.64	3420.83	-27.2
Authorisation					
Authorisation - Renewal	Per Authorisation	Fee	581.80	376.14	-35.4

Authorisation - New	Per Authorisation	Fee	635.66	419.06	-34.1
Site establishment fee					
Site Establishment - Per NMI	Per new NMI	Fee	49.25	35.88	-27.2
Conveyancing information					
Supply of conveyancing information - Per Desk Inquiry	Per Inquiry	Fee	83.39	59.27	-28.9
Planning studies					
Carrying out planning studies and analysis relating to distribution (including subtransmission and dual function assets) connection applications - SIMPLE JOBS	Per Hour	Quote	205.99	177.52	-13.8
Carrying out planning studies and analysis relating to distribution (including subtransmission and dual function assets) connection applications - COMPLEX JOBS	Per Hour	Quote	255.38	210.96	-17.4
Connection offer service					
Connection Offer Service (Basic)	Per Offer	Fee	35.08	23.81	-32.1
Connection Offer Service (Standard)	Per Offer	Fee	257.09	229.04	-10.9
Customer interface co-ordination					

Customer Interface co-ordination for contestable works	Per Hour	Quote	220.20	177.52	-19.4
Inv, rev and imp of remedial actions					
Investigation, review & implementation of remedial actions associated with ASP's connection work.	Per Hour	Quote	202.47	142.81	-29.5
Preliminary enquiry service					
Preliminary Enquiry Service - SIMPLE JOBS	Per Hour	Quote	179.64	89.06	-50.4
Preliminary Enquiry Service - COMPLEX JOBS	Per Hour	Quote	320.96	210.96	-34.3
Services involved in obtaining deeds of agreement					
Services involved in obtaining deeds of agreement in relation to property rights associated with contestable connections work	Per Hour	Quote	196.83	142.81	-27.5
Off peak conversions					
Off Peak Conversions	Per Job	Fee	125.38	111.50	-11.1
Clearance to work					
Clearance to Work	Per Job	Fee	2719.94	1981.50	-27.2
Rectification works					

Fitting of tiger tails (Labour) - Per Hour	Per Hour	Quote	155.11	133.80	-13.7
Fitting of tiger tails (Material) - Weekly Hire	Per Tiger Tail	Quote	4.84	4.84	–
High load escorts - Per Hour	Per Hour	Quote	155.11	133.80	-13.7
Rectification of illegal connections - Per Job	Per Job	Fee	620.42	535.19	-13.7
Provision of service crew / additional crew - Per Hour	Per Hour	Quote	155.11	133.80	-13.7
Meter test fee					
Meter Test Fee - Per Request	Per Job	Fee	661.92	401.39	-39.4
Reconnections / disconnections					
Disconnections (Meter Box) - Includes Reconnection	Per Disco	Fee	227.43	165.69	-27.2
Disconnections (Meter Load Tail) - Includes Reconnection	Per Disco	Fee	275.18	252.88	-8.1
Reconnections/Disconnections (Site Visit)	Per Visit	Fee	75.52	55.02	-27.2
Reconnection outside Normal business hours	Per Job	Fee	85.29	62.13	-27.2
Disconnections (Pole Top / Pillar Box) - Includes Reconnection	Per Job	Fee	469.50	417.96	-11.0
Disconnections at Pole Top / Pillar Box - Site Visit	Per Job	Fee	200.39	190.75	-4.8

Network tariff change request						
Network tariff change request	Per Job	Fee	91.99	0.00	We do not approve this fee.	
Special meter reads						
Special Meter Reads	Per Job	Fee	36.80	33.45	-9.1	
Move in move out meter reads						
Move in move out meter reads	Per Job	Fee	36.80	33.45	-9.1	
Recovery of debt collection costs						
Recovery of debt collection costs - dishonoured transactions	Per Job	Fee	24.14	16.02	-33.6	
Type 5-7 non-standard meter data services						
Type 5-7 Non Standard Meter data Services	Per Job	Fee	28.56	15.87	-44.4	
Franchise CT meter install						
Franchise CT Meter Install	Per Job	Fee	629.29	500.71	-20.4	
ROLR						
Services provided in relation to a Retailer of Last Resort (ROLR) event	Per Job	Quote	Quote Basis			
Meter transfer fee						

Meter Transfer Fee (Exit Fee)	Per Job	Fee Type	64.91	0.00	We do not approve this fee.
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Table 16.18 Maximum hourly labour rates (including on-costs and overhead) for quoted services (\$2014–15)

Classification	AER Final decision maximum labour rate - includes on-cost and overhead
Admin	89.06
Technical specialist	142.81
EO 7/Engineer	177.52
Field worker R4	133.80
Senior Engineer	210.96

Source: Marsden Jacob.

Table 16.19 AER final decision X factors for ancillary network services (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	-1.02	-1.07	-1.11	-1.10

Source: AER analysis.

A.2 Public Lighting Prices 2015-16

Table 16.20 – Final decision

Type	Tariff Class 1 & 2		Tariff 2 Opex		Total Tariff 1
	Revised Proposal	Final Decision	Revised Proposal	Final decision	
1 x 20 W Fluorescent	46.26	49.57	46.90		50.17
2 x 20 W Fluorescent	49.00	52.50	49.27		52.71
4 x 20 W Fluorescent	54.48	58.38	54.48		58.38
2 x 14 W Fluorescent	44.98	48.20	45.11		48.25
2 x 24 W Fluorescent	46.26	49.57	46.26		49.57
1 x 40 W Fluorescent	44.99	48.21	45.05		48.27
2 x 40 W Fluorescent	46.46	49.79	46.46		49.79
1 x 42 W Fluorescent	44.99	48.21	44.99		48.21
50W Mercury	44.15	47.31	53.93		56.47
80W Mercury	44.61	47.81	47.09		50.20
125W Mercury	44.61	47.81	44.94		48.11
250W Mercury	44.61	47.81	48.93		52.20
2 x 250W Mercury	45.71	48.98	45.71		48.98

400 W Mercury	44.61	47.81	49.59	52.89
50W Sodium	45.53	48.79	45.53	48.79
70W Sodium	45.53	48.79	45.53	48.79
90W Sodium	46.21	49.52	46.21	49.52
100W Sodium	46.21	49.52	74.66	76.47
120W Sodium	45.36	48.61	183.03	177.36
150W Sodium	45.36	48.61	51.67	54.95
250W Sodium	45.59	48.85	51.55	54.85
2 x 250W Sodium	47.66	51.08	47.66	51.08
310W Sodium	45.59	48.85	45.59	48.85
400 W Sodium	45.81	49.09	48.37	51.02
2 x 400 W Sodium	48.11	51.55	60.14	62.39
4 x 600W Sodium	52.70	56.47	52.70	56.47
60 W Incandescent	43.52	46.63	43.52	46.63
100 W Incandescent	43.52	46.63	43.52	46.63
500 W Incandescent	43.52	46.63	43.54	46.65
100 W Metal Halide	52.54	56.30	53.52	57.25

150 W Metal Halide	58.93	63.15	61.80	65.54
250 W Metal Halide	48.57	52.05	54.51	57.78
2 x 250 W Metal Halide	53.62	57.46	71.04	73.16
400 W Metal Halide	45.81	49.09	46.24	49.43
2 x 400 W Metal Halide	48.11	51.55	71.10	72.26
1000 W Metal Halide	45.81	49.09	45.52	48.78
600 W Sodium	45.81	49.09	69.00	71.38
Pole mounting bracket minor (<=3m)	10.88	11.66	12.06	12.81
Pole mounting bracket major (>3m)	10.88	11.66	17.03	17.61
Outreach Minor (<=2m)	10.88	11.66	13.93	14.64
Outreach Major (>2m)	10.88	11.66	13.13	13.86
Minor Column (<=9)	11.41	12.23	46.44	44.94
Major Column (>=9)	11.41	12.23	98.77	93.53

Source: AER analysis.

Type	Asset Value		Maintenance		Total Tariff	
	Revised Proposal	Final Decision	Revised Proposal	Final Decision	Revised Proposal	Final Decision
2x14W Energy Efficient Fluro - STD	53	43	55	55	108.39	98.26
2x24W Energy Efficient Fluro - STD	57	46	57	56	113.17	102.44
1x42W Compact Fluorescent - STD	46	37	55	55	100.98	92.25
50W Mercury - STANDARD	41	33	54	54	94.98	87.18
80W Mercury - STANDARD	37	30	55	54	91.54	84.49
70W Sodium - STANDARD	43	35	56	56	98.35	90.23
100W Sodium - STANDARD	49	40	57	56	105.61	96.28
100W Metal Halide - STANDARD	51	42	64	64	115.32	105.61
25W LED	78	68	54	54	131.81	121.42
Suburban 70W HPS c/w D2 PECB - STD	38	31	53	53	91.03	83.83
150W Sodium - STANDARD	53	43	56	55	108.22	98.22
150W Metal Halide - STANDARD	57	47	53	53	110.67	99.79
250W Sodium - STANDARD	53	44	56	56	109.28	99.13
250W Metal Halide - STANDARD	54	44	59	59	113.75	103.44
400W Sodium - STANDARD	58	47	56	56	113.60	102.69

80W Mercury - AEROSCREEN	43	35	55	54	97.53	89.36
Urban A/Screen 42W CFL c/w D2 PCB	56	45	55	55	110.75	100.19
150W Sodium - AEROSCREEN	57	46	56	55	112.03	101.31
150W Metal Halide - AEROSCREEN	61	50	72	72	133.33	121.70
250W Sodium (w/o PCB) - AEROSCREEN	57	46	56	56	112.31	101.59
250W Metal Halide - AEROSCREEN	57	47	59	59	116.78	105.90
400W Sodium - AEROSCREEN	61	50	56	56	116.92	105.39
400W Metal Halide - AEROSCREEN	62	50	59	59	121.02	109.35
Roadster A/Screen 100W HPS c/w PCB	52	43	57	56	108.78	98.87
80W Mercury - POST TOP	51	41	55	54	105.34	95.70
B2001 42WCFL c/w D2 PCB green - PT	81	66	53	53	134.32	119.01
250W Sodium - FLOODLIGHT	77	63	56	56	132.87	118.30
250W Metal Halide - FLOODLIGHT	78	64	59	59	137.35	122.61
400W Sodium - FLOODLIGHT	80	65	56	56	135.95	120.85
400W Metal Halide - FLOODLIGHT	81	66	59	59	140.05	124.81
150W Sodium - FLOODLIGHT	76	62	56	55	131.89	117.45
150W Metal Halide - FLOODLIGHT	81	66	72	72	153.20	137.84

Bracket - Minor <=3m	10	8	13	13	23.51	20.85
Bracket - Major >3m	61	46	13	13	74.79	58.90
Outreach - Minor <=2m	12	9	13	13	25.78	22.53
Outreach - Major >2m	28	21	13	13	41.70	34.35
Pole (Wood) - Minor - DEDICATED SL <=11m	89	66	14	14	103.14	80.11
Pole (Wood) - Major - DEDICATED SL >11m	173	129	14	14	187.03	142.36
Column (Steel) - Minor <=9m	296	220	14	14	310.30	233.83
Column (Steel) - Major >9m	622	462	14	14	635.81	475.38

Source: AER analysis.

Tariff Class 4 Type	Asset Value		Maintenance		Total Tariff	
	Revised Proposal	Final decision	Revised Proposal	Final decision	Revised Proposal	Final decision
2x14W Energy Efficient Fluro - STD	9	6	55	55	63.66	60.89
2x24W Energy Efficient Fluro - STD	9	6	57	56	65.75	62.82
1x42W Compact Fluorescent - STD	7	5	55	55	62.48	60.08
50W Mercury - STANDARD	7	5	54	54	60.65	58.49

80W Mercury - STANDARD	6	4	55	54	60.57	58.61
70W Sodium - STANDARD	7	5	56	56	62.61	60.36
100W Sodium - STANDARD	8	5	57	56	64.48	61.92
100W Metal Halide - STANDARD	8	6	64	64	72.54	69.86
25W LED	9	7	54	54	63.10	60.32
Suburban 70W HPS c/w D2 PCB - STD	6	4	53	53	59.36	57.37
150W Sodium - STANDARD	9	6	56	55	64.03	61.29
150W Metal Halide - STANDARD	9	6	53	53	62.53	59.57
250W Sodium - STANDARD	9	6	56	56	64.44	61.66
250W Metal Halide - STANDARD	9	6	59	59	68.22	65.39
400W Sodium - STANDARD	9	6	56	56	65.36	62.38
80W Mercury - AEROSCREEN	7	5	55	54	61.53	59.28
Urban A/Screen 42W CFL c/w D2 PCB	9	6	55	55	64.06	61.17
150W Sodium - AEROSCREEN	9	6	56	55	64.64	61.72
150W Metal Halide - AEROSCREEN	10	7	72	72	82.01	78.81
250W Sodium (w/o PCB) - AEROSCREEN	9	6	56	56	64.93	62.00
250W Metal Halide - AEROSCREEN	9	6	59	59	68.71	65.73

400W Sodium - AEROSCREEN	10	7	56	56	65.90	62.75
400W Metal Halide - AEROSCREEN	10	7	59	59	69.39	66.20
Roadster A/Screen 100W HPS c/w PECB	8	6	57	56	64.99	62.28
80W Mercury - POST TOP	8	6	55	54	62.80	60.16
B2001 42WCFL c/w D2 PECB green - PT	13	9	53	53	66.35	62.22
250W Sodium - FLOODLIGHT	12	9	56	56	68.25	64.30
250W Metal Halide - FLOODLIGHT	13	9	59	59	72.03	68.03
400W Sodium - FLOODLIGHT	13	9	56	56	68.97	64.89
400W Metal Halide - FLOODLIGHT	13	9	59	59	72.46	68.34
150W Sodium - FLOODLIGHT	12	9	56	55	67.85	63.94
150W Metal Halide - FLOODLIGHT	13	9	72	72	85.22	81.04
Bracket - Minor <=3m	2	1	13	13	15.44	14.69
Bracket - Major >3m	13	9	13	13	26.11	21.80
Outreach - Minor <=2m	3	2	13	13	15.91	15.01
Outreach - Major >2m	6	4	13	13	19.22	17.21
Pole (Wood) - Minor - DEDICATED SL <=11m	19	12	14	14	32.53	26.29
Pole (Wood) - Major - DEDICATED SL >11m	36	24	14	14	49.98	37.90

Column (Steel) - Minor <=9m	19	13	14	14	33.27	26.78
Column (Steel) - Major >9m	36	24	14	14	50.20	38.05

Source: AER analysis.

A.3 Metering

Table 16.21 Annual metering charge – Final decision (\$ nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19
Residential anytime	Non-capital	13.35	13.98	14.63	15.32
	Capital	1.45	1.52	1.59	1.66
Residential TOU – Type 6 meter	Non-capital	29.12	30.49	31.91	33.41
	Capital	1.45	1.52	1.59	1.66
Residential TOU - Type 5 meter	Non-capital	122.11	127.82	133.81	140.07
	Capital	1.45	1.52	1.59	1.66
Small business anytime	Non-capital	20.24	21.18	22.17	23.21
	Capital	1.45	1.52	1.59	1.66
Small business TOU - Type 6 meter	Non-capital	49.77	52.09	54.53	57.08
	Capital	1.45	1.52	1.59	1.66
Small business TOU – Type 5 meter	Non-capital	142.75	149.43	156.42	163.75
	Capital	1.45	1.52	1.59	1.66

Controlled load	Non-capital	3.40	3.56	3.73	3.90
	Capital	1.45	1.52	1.59	1.66
Solar	Non-capital	3.40	3.56	3.73	3.90
	Capital	1.45	1.52	1.59	1.66

Source: AER analysis

Note: Prices for 2016–17 to 2018–19 are indicative only and will be adjusted for actual CPI during the AER's annual pricing approval processes.

Table 16.22 AER final decision X factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19
X factor	-2.25	-2.25	-2.25

Source: AER analysis.

Table 16.23 Upfront capital charge – Final decision

	Interval (3G modem) (\$2014–15)	Interval (without 3G modem) (\$2014–15)	Accumulation (\$2014–15)
Whole current single element meter	Single phase	643.40	40.61
	Single phase import/export	643.40	85.26
	Poly phase	457.93	109.42
	Poly phase import/export	457.93	111.12
Current transformer meter	Single phase	N/A	N/A

Whole current dual element meter	Single phase import/export	N/A	N/A	N/A
	Poly phase	554.18	359.60	359.60
	Poly phase import/export	554.18	359.60	359.60
	Single phase	733.42	175.28	175.28
	Single phase import/export	733.42	175.28	175.28
	Poly phase	N/A	N/A	N/A
	Poly phase import/export	N/A	N/A	N/A

Source: AER analysis.

Table 16.24 AER final decision X factors for upfront capital charge (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	0.0	0.0	0.0	0.0

Source: AER analysis.