



**FINAL DECISION**  
**Powercor distribution**  
**determination**  
**2016 to 2020**

**Attachment 16 – Alternative**  
**control services**

May 2016

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## Note

This attachment forms part of the AER's final decision on Powercor's distribution determination for 2016–20. It should be read with all 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 – f-factor scheme

# Contents

<b>Note</b> .....	<b>16-2</b>
<b>Contents</b> .....	<b>16-3</b>
<b>Shortened forms</b> .....	<b>16-4</b>
<b>16 Alternative control services</b> .....	<b>16-6</b>
<b>16.1 Ancillary network services</b> .....	<b>16-6</b>
16.1.1 Final decision .....	16-6
16.1.2 Powercor's revised proposal .....	16-10
16.1.3 Assessment approach.....	16-10
16.1.4 Reasons for final decision .....	16-11
<b>16.2 Public Lighting</b> .....	<b>16-12</b>
16.2.1 Final decision .....	16-12
16.2.2 Powercor's revised proposal .....	16-13
16.2.3 Assessment approach.....	16-13
16.2.4 Reasons for final decision .....	16-13
<b>16.3 Metering</b> .....	<b>16-16</b>
16.3.1 Final decision .....	16-17
16.3.2 Powercor's revised proposal .....	16-22
16.3.3 Assessment Approach .....	16-25
16.3.4 Reasons for final decision .....	16-27
<b>A Ancillary network services prices</b> .....	<b>16-37</b>
<b>B Annual metering charges unders and overs account</b> .....	<b>16-39</b>

## Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
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

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

## 16 Alternative control services

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

In this attachment, we set out our final decision on the prices Powercor is allowed to charge customers for the provision of alternative control services (ancillary network services, public lighting and metering).

### 16.1 Ancillary network services

For the purposes of this final decision, we refer to the service groups previously identified as 'fee based services' and 'quoted services' collectively as a single group called 'ancillary network services'.<sup>1</sup>

Ancillary network services share the common characteristic of being non-routine services provided to individual customers on an as requested basis.<sup>2</sup> The existing fee based services and quoted services groupings describe the basis on which service prices are determined.<sup>3</sup>

Prices for fee based services are predetermined, based on the cost of providing the service and the average time taken to perform it. These services tend to be homogenous in nature and scope, and can be costed in advance of supply with reasonable certainty.

By comparison, prices for quoted services are based on quantities of labour and materials, with the quantities dependent on a particular task. Prices for quoted services are determined at the time of a customer's enquiry and reflect the individual requirements of the customer and service requested. It is not possible to list prices for quoted services in this decision (any such list would only be for illustrative purposes).

#### 16.1.1 Final decision

We generally accept Powercor's revised proposal for ancillary network services. For these services, Powercor's proposed prices for 2016 do not exceed prices based on maximum labour rates (for the distributor's labour types) and times taken to perform the service, which we consider efficient in the provision of these services.

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<sup>1</sup> AER, *Final framework and approach paper for the Victorian electricity distributors—Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 60.

<sup>2</sup> AER, *Final framework and approach paper for the Victorian electricity distributors—Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 60.

<sup>3</sup> AER, *Final framework and approach paper for the Victorian electricity distributors—Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 60.

Our preliminary decision approved Powercor's prices for 2016 in \$2015 terms and noted that these were to be escalated into \$2016 terms in Powercor's 2016 pricing proposal using the approved CPI adjustment.<sup>4</sup> We approved Powercor's 2016 pricing proposal in December 2015.<sup>5</sup> Powercor's revised proposal prices are the same as those we approved in Powercor's 2016 pricing proposal.<sup>6</sup>

However, we do not accept Powercor's revised proposals on labour price growth. We have applied our final decision (updated) labour price growth, which is set out in Table 16.1 and is discussed in attachment 7—operating expenditure.

We also note that our preliminary decision inadvertently published a price for reserve feeder maintenance as a fee based service when this service is classified as a quoted service. In consultation with Powercor, this error was corrected for in Powercor's 2016 pricing proposal.<sup>7</sup> Our final decision has reflected this correction in table 16.5 in appendix A.1.

For 2017 and for each subsequent year of the 2016–20 regulatory control period, the prices for ancillary network services will be determined by applying our final decision forms of control, which are set out below.

## Form of control

Our final decision is to apply price caps as the forms of control to ancillary network services. Figure 16.1 and Figure 16.2 set out the control mechanism formulas for fee based and quoted services, respectively. They are consistent with our final framework and approach,<sup>8</sup> and our preliminary decision.<sup>9</sup> Powercor accepted these formulas in its revised regulatory proposal.<sup>10</sup>

### Form of control—fee based services

Our final decision applies a price cap form of control for fee based services. Under this form of control, we set a schedule of prices for 2016 which are set out in Table 16.13 of appendix A.1. For 2017 and for each subsequent year of the 2016–20 regulatory control period, the prices for ancillary network services are determined by adjusting the

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<sup>4</sup> AER, *Preliminary decision: Powercor distribution determination 2016 to 2020: Attachment 16: Alternative control services*, October 2015, pp. 45–46.

<sup>5</sup> Powercor, *Powercor 2016 pricing proposal*, December 2016.

<sup>6</sup> Powercor, *Powercor 2016 pricing proposal*, December 2016, pp. 73–85.

<sup>7</sup> Email to AER from CitiPower and Powercor titled: *Revised 2016 pricing proposals – CitiPower & Powercor*, 9 December 2015

<sup>8</sup> AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 July 2016*, 24 October 2014, pp. 92–93.

<sup>9</sup> AER, *Preliminary decision: Powercor distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, pp. 7–10.

<sup>10</sup> Powercor, *Revised regulatory proposal 2016–20*, 6 January 2016, pp. 425–426. (Powercor, *Revised regulatory proposal*, 6 January 2016)



previous year's prices by the formula in Figure 16.1. The X factors in this formula adjust for annual labour price growth.

**Figure 16.1 Fee based ancillary network services formula**

$$\bar{p}_t^i \geq p_t^i \quad i=1, \dots, n \text{ and } t=2,3,4,5$$

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

Where:

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

$p_t^i$  is the price of service i in year t

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

t is the regulatory year

$CPI_t$  is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities<sup>11</sup> from the June quarter in year t-2 to the June quarter in year t-1, calculated using the following method:

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

divided by

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

minus one.

For example, for the 2017 year, t-2 is the June quarter 2015 and t-1 is the June quarter 2016 and in the 2018 year, t-2 is the June quarter 2016 and t-1 is the June quarter 2017 and so on.

$X_t^i$  is the X factor for service i in year t, as set out in Table 16.1.<sup>12</sup>

<sup>11</sup> If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

<sup>12</sup> Our final F&A erroneously stated the X factor in this formula would incorporate annual adjustments for updates to the trailing cost of debt. However, we note these services do not incorporate a cost of capital and therefore the X factors will not be applied in this manner. Rather, consistent with the price caps applied to these services in other jurisdictions, the X factors will adjust for annual labour price growth as set out in Table 16.1.

**Table 16.1 AER final decision on X factors for each year of the 2016–20 regulatory control period (per cent)**

	2017	2018	2019	2020
X factor	-0.37	-0.79	-0.96	-1.02

Source: AER analysis.

Note: To be clear, the labour price growth is positive for each year of the regulatory control period. However, in operating as de facto X factors in the price caps, positive labour price growth is presented as a negative value.

## Form of control—quoted services

Our final decision applies a price cap formula to determine the cost build-up of services that are priced on a ‘quoted’ basis.<sup>13</sup> Figure 16.2 sets out the price cap formula and Table 16.14 in appendix A.1 sets out the approved 2016 labour rates for quoted services.

### Figure 16.2 Quoted services formula

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

Where:

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

$CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities<sup>14</sup> from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

<sup>13</sup> AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 July 2016*, 24 October 2014, p. 89.

<sup>14</sup> If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

For example, for the 2017 year, t–2 is the June quarter 2015 and t–1 is the June quarter 2016 and in the 2018 year, t–2 is the June quarter 2016 and t–1 is the June quarter 2017 and so on.

$X_t^i$  is the X factor for service i in year t, as set out in Table 16.1.<sup>15</sup>

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

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

### 16.1.2 Powercor's revised proposal

Powercor generally accepted our preliminary decision on ancillary network services.<sup>16</sup> In its revised proposal, Powercor accepted the changes we made to its:

- times taken to perform meter accuracy tests, and
- calculation of the CPI escalator from 2014 to 2015.<sup>17</sup>

However, Powercor did not accept our preliminary decision for labour price growth.<sup>18</sup>

### 16.1.3 Assessment approach

As Powercor accepted our preliminary decision—with the exception of labour price growth—our final decision assessment approach is to ensure its revised proposal is compliant with our preliminary decision.

Our preliminary decision undertook a detailed assessment of Powercor's initial proposal by focussing on the key inputs in determining prices for ancillary network services. In summary, our preliminary decision considered:

- maximum total labour rates we developed for Victoria. Our findings were informed by our consultant's, Marsden Jacob Associates', analysis<sup>19</sup>
- since labour is the key input in determining an efficient level of prices for ancillary network services, we focused on comparing Powercor's proposed total labour rates against our developed maximum total labour rates
- the other key inputs, being:

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<sup>15</sup> The X factors applied in this formula adjust for annual labour price growth.

<sup>16</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 468.

<sup>17</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 467–472.

<sup>18</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 468.

<sup>19</sup> Marsden Jacob Associates, *Final provision of advice in relation to alternative control services—public version*, 20 October 2014.

- proposed times taken to perform the service, and
- contractor rates.

As per section 16.1.4.1 of our preliminary decision, we obtained maximum rates for the following labour components:

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

We applied these maximum (component) rates to derive maximum total labour rates (for particular labour types) which are presented in Table 16.2. We consider that using our maximum total labour rates to determine prices for services will provide Powercor 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.<sup>20</sup>

**Table 16.2 Maximum allowed total labour rates**

AER labour category	AER maximum total labour rates (\$2014)
Administration	91.88
Technical	160.79
Engineer	172.28
Field worker	160.79
Senior engineer	229.70

Source: AER analysis.

Our final decision assessment on labour price growth is discussed in attachment 7—operating expenditure.

### 16.1.4 Reasons for final decision

We accept Powercor's revised proposal where it has accepted our preliminary decision.<sup>21</sup> However, we do not accept Powercor's revised proposal labour price growth forecast. Our reasons are discussed in attachment 7—operating expenditure.

Our preliminary decision accepted some aspects of Powercor's initial proposal, but made the following adjustments:

<sup>20</sup> NEL, ss. 7A and 16.

<sup>21</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 468.

- adjusted the CPI escalation from 2014 to 2015 to include the ABS published September 2014 quarter index<sup>22</sup>
- substituted in our preliminary decision labour price growth forecast<sup>23</sup>
- adjusted times taken to perform some services based on benchmark times taken by other distributors.<sup>24</sup>

Our preliminary decision considered these changes were necessary to determine an efficient level of prices for Powercor's ancillary network services.

Powercor reflected our preliminary decision changes in its 2016 pricing proposal,<sup>25</sup> which we approved in December 2015. Powercor accepted the approved 2016 prices in its revised proposal.<sup>26</sup> These approved 2016 prices are set out in Table 16.13 and Table 16.14 in appendix A.1.

## 16.2 Public Lighting

### 16.2.1 Final decision

We do not approve the proposed public lighting charges because we have determined;

- a real pre-tax WACC of 4.35 per cent instead of the proposed 4.27 per cent
- labour escalation of 0.37 per cent instead of the proposed 1.76 per cent in 2017.

In all other respects we have approved the proposal.

### Form of control

We are applying caps on the charges of individual services consistent with the current regulatory arrangements in Victoria.

Although the public lighting service is subject to an alternative control classification the control mechanism is implemented through a public lighting model under a building block approach.

Compliance with the control mechanism is to be demonstrated by the Victorian distributors through the annual pricing proposal, by updating the forecast CPI for the actual CPI each year.

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<sup>22</sup> AER, *Preliminary decision: Powercor distribution determination 2016 to 2020: Attachment 16: Alternative control services*, October 2015, p. 17

<sup>23</sup> AER, *Preliminary decision: Powercor distribution determination 2016 to 2020: Attachment 16: Alternative control services*, October 2015, p. 17

<sup>24</sup> AER, *Preliminary decision: Powercor distribution determination 2016 to 2020: Attachment 16: Alternative control services*, October 2015, pp. 18–19.

<sup>25</sup> Powercor, *Powercor 2016 pricing proposal*, 19 November 2015, pp. 1–95.

<sup>26</sup> Powercor, *PC 2016–20 Revised proposal – ACS model*, January 2016.

## 16.2.2 Powercor's revised proposal

Powercor did not accept the AER's preliminary decision WACC or labour escalators but has accepted all other aspects of the AER's preliminary decision.<sup>27</sup>

## 16.2.3 Assessment approach

Our final decision assessment approach is the same as our preliminary decision. We have also considered Powercor's revised regulatory proposal.

Our preliminary decision undertook a detailed assessment of Powercor's initial proposal by focussing on the key inputs in determining prices for public lighting. It benchmarked inputs and costs of Victorian distributors against their peers. We did this based on the inputs decided in the 2011–15 determination and included in the modelling. In this way we achieved consistency with the approach we adopted for the 2011 determination and by the State regulator before that.<sup>28</sup>

This approach achieves consistency in assumptions and costs across distributors; nonetheless public lighting charges will always vary somewhat amongst the five Victorian distributors because of each distributor's particular circumstances (size of asset base, geographic patch to cover, mix of luminaire types, among others). We have previously explained this in prior public lighting determinations.<sup>29</sup>

## 16.2.4 Reasons for final decision

We have adopted the same estimate of WACC as for standard control services. The reasons for the real pre-tax WACC are discussed in attachment 3 — Rate of return.

Our final decision approved labour escalation is set out in attachment 7 — operating expenditure. The approved labour escalators are consistent with standard control services.

We accept the materials prices proposed. The Greenhouse Alliance submission argued that the proposed materials prices are in some instances excessive.<sup>30</sup> We however consider that the proposed prices are within the efficient range of prices that are available from suppliers in the market place and that the least cost product will not necessarily be the most efficient option for distributors.

The prices provided in Greenhouse Alliance submission were not at all dissimilar to those that have been provided by distributors, and we understand the Greenhouse Alliance recommends distributors select the cheapest face value material prices available. The least cost purchase price is not necessarily the most effective or efficient

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<sup>27</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 472–473.

<sup>28</sup> Essential Services Commission of Victoria, *Review of Public Lighting Excluded Services*, August 2004 Final Decision, pp. 70–73.

<sup>29</sup> AER, *2011-15 Victorian Electricity Distribution, Final Decision*, p. 836.

<sup>30</sup> Greenhouse Alliance, *Submission to AER Preliminary Decision*, 6 January 2016, p. 2.

for distributors, as distributors need to take into account the reliability of the supplier, the quality of the products that they supply and the total costs for distributors over the life of the materials.

Distributors may also want to source materials from more than one supplier, in order to ensure competitive tension in the market for public lighting inputs. To source from only one supplier runs the risk of supplier monopoly pricing and service quality issues.

For these reasons, we have decided not to simply go with the cheapest costs for public lighting inputs. We think the range of input costs set out by the distributors in their models—consistent with past practice—still provides the best estimate of materials costs over the 2016–20 regulatory control period. We accept that Powercor must and rightly has taken into account a range of factors in selecting efficient materials supplier's products such as the life time cost, reliability and quality of the material supplied. This is consistent with how Powercor has sought to procure public lighting cost inputs, and recovered them through the public lighting charges model.

Final decision charges for each light type are set out in .

### *Victorian Public Lighting Framework*

The framework for public lighting in Victoria is set out in the Victorian Public Lighting Code 2005 (the Code).

Distributors' licences' stipulate that the terms and conditions for providing public lighting services must be consistent with the Code. Importantly, the Code only extends to the provision by distributors of the ongoing operation, maintenance and replacement of public lighting assets that they own (clause 1.3).

The explanatory note in clause 3 of the Code states that the distributor and the public lighting customer may agree that after the construction and commissioning of the assets, ownership of the assets will transfer to the distributor. Where such an agreement is made, the assets become subject to the applicable provisions of the Code. If no agreement is reached, asset ownership remains with the public lighting customer and are not subject to regulation under the Code.

Our decision on public lighting charges is made in accordance with the Code and as such, we are only determining the charges to be levied by distributors for assets that they own.

### *Service Standards*

The Code sets out minimum levels of service from distribution businesses and protections for Councils for public lighting in Victoria.

In relation to service standards we consider that there is a trade-off between the charges paid by Councils and the service provided by distribution businesses.

We see our role as setting a minimum level of protection. Councils can seek to negotiate with distributors to secure lower charges than those set by our determination

but the Code mandates minimum service standards. Regulated charges are set for these minimums. Councils can negotiate for superior service but the trade-off is likely to be higher charges for a customised service.

**Table 16.3 Public Lighting Charges (\$ nominal)**

	2016	2017	2018	2019	2020
Mercury Vapour 80 watt	48.09	50.82	53.44	56.34	59.21
Sodium High Pressure 150 watt	90.64	94.52	98.48	102.79	107.12
Sodium High Pressure 250 watt	91.83	95.91	100.02	104.51	109.01
Fluorescent 20 watt	101.94	107.74	113.30	119.44	125.53
Fluorescent 40 watt	101.94	107.74	113.30	119.44	125.53
Mercury Vapour 50 watt	66.84	70.64	74.29	78.31	82.30
Mercury Vapour 125 watt	64.92	68.61	72.15	76.06	79.94
Mercury Vapour 250 watt	69.79	72.89	76.02	79.43	82.85
Mercury Vapour 400 watt	80.81	84.40	88.02	91.97	95.93
Mercury Vapour 700 watt	122.13	127.56	133.03	139.00	144.99
Sodium Low Pressure 90 watt	122.37	127.60	132.95	138.77	144.61
Sodium Low Pressure 180 watt	122.37	127.60	132.95	138.77	144.61
Sodium High Pressure 400 watt	122.13	127.56	133.03	139.00	144.99
Incandescent 100 watt	133.68	141.28	148.57	156.63	164.61
Incandescent 150 watt	133.68	141.28	148.57	156.63	164.61
Metal Halide 250 watt	122.13	127.56	133.03	139.00	144.99
Metal Halide 400 watt	122.13	127.56	133.03	139.00	144.99
Metal Halide 70 watt	101.94	107.74	113.30	119.44	125.53
Metal Halide 150 watt	120.55	125.71	130.98	136.71	142.47
T5 2X14W	39.68	39.43	40.26	41.06	41.84
T5 (2x24W)	39.03	38.79	39.60	40.40	41.16
Compact Fluoro 32W	38.14	37.91	38.70	39.47	40.22
Compact Fluoro 42W	38.14	37.91	38.70	39.47	40.22
LED 18W	26.43	25.73	26.18	26.57	26.91
LED 47W	26.43	25.73	26.18	26.57	26.91

Source: AER analysis.



## 16.3 Metering

We are responsible for the economic regulation of the regulated metering services provided by the Victorian distribution businesses.

Type 1–4 (advanced) meters for large customers are competitively provided in Victoria and are therefore unregulated. We regulate all other metering in Victoria.

Since 2009, there has been a derogation in Victoria which has meant that the scope of our regulation has been set under the Advanced Metering Infrastructure (AMI) Cost Recovery Order-in-Council (the Order) made by the Victorian Government. The Order mandated distributors install advanced remotely read interval meters together with appropriate communications and information technology systems for all small electricity customers in Victoria.

Our Framework and Approach Paper (F&A) introduced the term 'smart meters' to refer to the advanced remotely read interval meters installed under the derogation.<sup>31</sup> From 2009 to 2015, the Order directed the AER to set budgets and charges for the AMI rollout under a prescribed regime instead of the NER.

The rollout of smart meters in Victoria is now effectively complete with almost 2.8 million meters installed across the state.<sup>32</sup> As a result, metering in Victoria is entering a "business-as-usual" phase in the 2016-20 regulatory control period. To facilitate this transition, metering services will now be regulated under the NEL and NER, subject to certain modifications set out in the Order.

The AEMC published its final rule change on expanding competition in metering on 26 November 2015.<sup>33</sup> For jurisdictions that are part of the national metering framework, the new rules will take effect from 1 December 2017.<sup>34</sup> It is not clear at this stage the extent to which the Victorian Government will adopt the national framework.

We make this final decision taking into account the current jurisdictional context. This final decision focuses on facilitating smooth transition from the Order to the NER, noting the national context for introducing competition to metering. We have maintained many of the same elements currently in the Order: a revenue cap and recovering the capital for new and upgraded meters as part of the annual charge. However, the Order requires us to set restoration and exit fees in accordance with the Order and also provides additional factors we may have regard to when determining 2016-20 metering service charges.

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<sup>31</sup> AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p. 48.

<sup>32</sup> Victorian Government, Department of Economic Development, Jobs, Transport and Resources <http://www.smartmeters.vic.gov.au/about-smart-meters/end-of-rollout>, accessed 11 October 2015.

<sup>33</sup> AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

<sup>34</sup> AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

In this section of the alternative control services attachment, we explain our decision on 'default' metering services that are common to regulated metering customers:

- Type 5–6 and smart metering services (regulated service only), referred to as annual metering charges (revenue cap)
- Type 5–6 and smart metering exit fees (individual price caps)
- Type 7 metering charges (individual price caps).

Our determination on ancillary metering services (specifically requested services) is set out in the ancillary network services section of this chapter (section 16.1)

### 16.3.1 Final decision

#### 16.3.1.1 Cost Allocation

Our final decision does not accept the advanced meter infrastructure (AMI) cost allocation proposed by Powercor. Our final decision on the allocation between alternative control services and standard control services is set out in Table 16.4 below.

**Table 16.4 Final decision - Powercor's allocation of AMI IT and Comms (% allocated to ACS and SCS)**

	Percentage allocated to ACS	Percentage allocated to SCS
Initial proposal	33	67
AER preliminary decision	100	0
Revised proposal	33	67
AER final decision	57	43

Source: AER analysis.

#### 16.3.1.2 Annual metering charges

Our final decision accepts a total revenue requirement of \$343.8 (\$ nominal) over the 2016–20 regulatory control period for metering services. It includes the following building blocks:

- forecast capex of \$45.1 million (\$2015), amounting to 86 percent of Powercor's proposal
- forecast opex of \$82.2 million (\$2015), which due to a change in cost allocation is higher than Powercor's revised proposal of \$76.3 million (\$2015)
- an opening metering regulatory asset base as at 1 January 2016 of \$332.1 million, rather than the proposed \$333.4 million (\$ nominal)
- with respect to depreciation, standard asset lives of 15 years for metering assets and 7 years for communications, IT and other assets

- the same WACC and gamma values for standard control network services, subject to annual adjustments for the return on debt.

The above building blocks result in the following approved revenue requirement for metering shown in Table 16.5.

**Table 16.5 Final decision – metering annual revenue requirement for the 2016–20 regulatory control period (\$ nominal)**

	2015	2016	2017	2018	2019	2020
Depreciation		32.0	35.1	38.0	36.2	27.0
Return on capital		20.3	19.4	18.1	16.1	14.2
Opex <sup>a</sup>		17.3	17.1	17.6	18.1	18.7
Tax		0.0	0.0	0.0	0.0	0.3
Unsmoothed revenue requirement		69.6	71.6	73.7	70.4	60.1
X factor (%) <sup>b</sup>		13.81	10.75	8.00	8.00	8.00
Smoothed revenue requirement	89.7	79.2	72.3	68.0	64.1	60.3

Source: AER analysis.

(a) Operating expenditure includes debt raising costs.

(b) The X factor from 2017 to 2020 will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

Our final decision on Powercor's approved revenue requirement will lead to lower metering prices over the 2016–20 regulatory control period. As metering services is subject to a revenue cap, we have not set prices in this final decision. Actual metering prices will be approved during the annual pricing process.

Broadly we expect the price path to follow the X factors included in Table 16.5 above. That is, a decrease in prices in 2016 as a consequence of the positive X factor we set in our preliminary decision. Under the CPI–X framework a positive X factor represents a real decrease in revenue. In accordance with our approach to revenue smoothing, this will then be followed by further decreases in prices in each remaining year of the 2016–20 regulatory control period.

There are two key drivers effecting our final decision on Powercor's revenue requirement, and hence its price path for metering services. The first is Powercor has now entered into a business as usual (BAU) phase in the 2016–20 regulatory control period. This BAU phase has more modest cost requirements than in the previous period when Powercor was rolling out its advanced metering infrastructure. The other key driver is a reallocation of a proportion of Powercor's operating costs. In our

preliminary decision, we allocated all of Powercor's metering related opex to alternative control services. This final decision looks at the allocation of these costs more carefully following submissions to the preliminary decision (see 16.3.1.1). As a consequence, a proportion of opex allocated to alternative control services in our preliminary decision has been reallocated to standard control services in this final decision. This has a downward effect on Powercor's revenue for alternative control metering services from 2017 onwards, but a corresponding upward effect on standard control services.

### 16.3.1.3 Form of control for annual metering charges

As per our preliminary decision, our final decision applies a revenue cap form of control to annual metering charges.<sup>35</sup> Under this form of control, annual metering charges revenues are capped for each year of the 2016–20 regulatory control period. Figure 16.3 contains the annual metering charges revenue cap formula.

Under a revenue cap, Powercor's annual metering charges revenue will be adjusted annually to clear (or true-up) any under or over recovery of actual revenue collected. These true-ups will be calculated through the annual metering charges unders and overs account in accordance with appendix B.

Our final decision has changed the approach to true-up under and over recovered revenues from our preliminary decision. Our final decision includes an additional true-up for estimated under and over recovery of revenues for regulatory year  $t-1$ .<sup>36</sup> We have made this change to be consistent with the approach applied for the distribution use of system charges unders and overs account.<sup>37</sup>

Our final F&A stated the revenue cap for any given regulatory year is the maximum allowable revenue for annual metering charges. However, our preliminary decision considered the use of maximum allowable revenue might be confused with maximum allowed revenue which is a defined term in the NER relating to transmission services. To avoid confusion, we used 'total annual revenue for metering' (or TARM) for clarity. This has been retained for our final decision.

For each year after the first year of a regulatory control period, side constraints will apply. Consistent with the application of side constraints for standard control services, the permissible percentage increase will be the greater of CPI-X plus 2 per cent or CPI plus 2 per cent. The side constraint formula is set out in Figure 16.4.

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<sup>35</sup> AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 July 2016*, 24 October 2014, pp. 89–93.

<sup>36</sup> Year  $t$  represents the forthcoming regulatory year. Therefore, year  $t-2$  and year  $t-1$  are the two regulatory years prior to year  $t$ . By way of example, if year  $t$  is the year 2018 then year  $t-2$  is 2016 and year  $t-1$  is 2017.

<sup>37</sup> Our final distribution use of system unders and overs account is discussed in attachment 14 – Control mechanisms.

### Figure 16.3 Annual metering charges revenue cap formula

$$(1) \quad TARM_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij} \quad i=1,\dots,n \text{ and } j=1,\dots,m \text{ and } t=1,\dots,5$$

$$(2) \quad TARM_t = AR_t + T_t + B_t \quad t = 1,2,\dots,5$$

$$(3) \quad AR_t = AR_{t-1}(1 + \Delta CPI_t)(1 - X_t) \quad t = 1,2,\dots,5$$

where;

$TARM_t$  is the total annual revenue for annual metering charges in year t.

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

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

$AR_t$  is the annual revenue requirement for year t. When year t is the first year of the 2016–20 regulatory control period,  $AR_t$  is the annual revenue requirement in the annual metering charges Post Tax Revenue Model (PTRM) for year t.

$T_t$  is equal to zero for all years except 2017 and is a once off adjustment to 2017 charges for the unders and overs recoveries relating to Advanced Metering Infrastructure actual revenues and actual costs incurred in 2014 and 2015.

$B_t$  is the sum of annual adjustment factors in year t as calculated in the unders and overs account in appendix B.

$AR_{t-1}$  is the annual revenue requirement for year t–1.

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities<sup>38</sup> from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

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

divided by

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

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<sup>38</sup> If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

minus one.

For example, for the 2017 regulatory year, t–2 is June quarter 2015 and t–1 is June quarter 2016 and for the 2018 regulatory year, t–2 is June quarter 2016 and t–1 is June quarter 2017 and so on.

$X_t$  is the X factor for each year of the 2016–20 regulatory control period as determined in the annual metering charges PTRM.

### Figure 16.4 Side constraints

$$p_t^i \leq p_{t-1}^i (1 + \Delta CPI_t) (1 - X_t^i) (1 + 2\%) + T_t^i + B_t^i$$

where:

$p_t^i$  is the price of annual metering charges service 'i' in year t.

$p_{t-1}^i$  is the price of annual metering charges service 'i' in year t–1.

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities<sup>39</sup> from the June quarter in year t–2 to the June quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

For example, for the 2017 regulatory year, t–2 is June quarter 2015 and t–1 is June quarter 2016 and for the 2018 regulatory year, t–2 is June quarter 2016 and t–1 is June quarter 2017 and so on.

$X_t$  is the X factor for each year of the 2016–20 regulatory control period as determined in the annual metering charges PTRM.

$T_t^i$  is the annual percentage change for the unders and overs recoveries relating to Advanced Metering Infrastructure actual revenues and actual costs incurred in 2014 and 2015. It is equal to zero for all years except 2017 and is a once-off adjustment to 2017 charges.

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<sup>39</sup> If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

$B_t'$  is the annual percentage change from the sum of annual adjustment factors in year t as calculated in the unders and overs account in appendix B.

With the exception of the CPI and the X factor, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the total annual revenue formula) for each factor by the expected revenues for regulatory year t-1 (based on the prices in year t-1 multiplied by the forecast quantities for year t).

#### 16.3.1.4 Metering exit fees

We are required to specify an exit fee for Powercor.<sup>40</sup>

The exit fees we have accepted in this final decision are set out in Table 16.6.

**Table 16.6 Powercor final decision – meter exit fees (\$ nominal)**

Meter type	2017	2018	2019	2020
AMI single phase	498.48	464.64	424.22	390.13
AMI three phase	606.01	568.00	522.79	483.42
AMI three phase current transformer	1 188.43	1 125.80	1 065.38	1 007.83
Non AMI NMI	41.80	43.10	44.51	46.00

Source: AER analysis.

### 16.3.2 Powercor's revised proposal

#### 16.3.2.1 Cost Allocation

The Victorian businesses have all proposed different ways to allocate the costs that were previously regulated under the Order across standard and alternative control services. Our preliminary decision was that the metering costs should be recovered through alternative control services and we reallocated Powercor's metering costs from standard control services to alternative control.<sup>41</sup>

Powercor has maintained its proposal that a portion of the metering costs should be allocated to standard control services.<sup>42</sup>

<sup>40</sup> NER, cl. 11.17.6.

<sup>41</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-28.

<sup>42</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 149.

### 16.3.2.2 Annual metering charges

With regard to the annual metering charge, Powercor's revised proposal:

- applied the general pricing structure set out in our preliminary decision
- submitted a revised capex of \$52.5 million for annual metering charges<sup>43</sup>, compared to the AER's preliminary decision accepting \$33.5 million (\$2015)<sup>44</sup>
- submitted a revised opex of \$76.3 million for annual metering charges<sup>45</sup>, compared to the AER's preliminary decision accepting \$91.7 million (\$2015)<sup>46</sup>
- accepts our preliminary decision of an opening metering asset base (MAB) value as of 1 January 2016 of \$333.4 million (\$nominal)<sup>47</sup>
- with respect to depreciation, standard asset lives of 15 years for metering assets and 7 years for communications, IT and other metering assets.<sup>48</sup>

Powercor's revised proposal annual revenue requirement for the 2016–20 regulatory control period is set out in Table 16.7 below.

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<sup>43</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 454.

<sup>44</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-28.

<sup>45</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 457.

<sup>46</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p 16-28. This is lower than our preliminary decision on account that Powercor have maintained an allocation of metering cost to standard control services, rather than our preliminary decision to allocate all the costs to alternative control services.

<sup>47</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 459.

<sup>48</sup> Powercor, *Revised regulatory proposal 2016–20, Metering PTRM an exit fees*, January 2016, 'PTRM input' tab.



**Table 16.7 Proposed metering annual revenue requirement (\$ nominal)**

	2016	2017	2018	2019	2020
Depreciation	31.7	34.9	38.0	36.4	27.2
Return on capital	20.1	19.3	18.2	16.3	14.5
Opex	15.8	15.8	16.4	17.1	17.8
Tax	0.0	0.0	0.0	0.0	0.7
Unsmoothed revenue requirement	67.5	70.0	72.6	69.8	60.2
X-factor (%)	13.96	14.00	7.25	7.25	7.25
Smoothed revenue requirement	79.2	69.8	66.3	63.1	60.0

Source: Powercor, *Revised regulatory proposal*, January 2016, p. 461. (Powercor, Revised regulatory proposal 2016–20, Metering PTRM an exit fees, January 2016, 'Revenue summary' tab).

Powercor stated that the key change in the annual revenue requirement in the revised proposal is the timing of the introduction of metering contestability which is now scheduled for 1 December 2017.<sup>49</sup>

### 16.3.2.3 Metering exit fee

Powercor did not accept the AER's preliminary determination of the value of the exit fee and has updated the calculation to reflect its revised operating and capital expenditure requirements.<sup>50</sup>

The revised proposal meter exit fees are set out in Table 16.8.

**Table 16.8 Powercor revised proposal exit fees (\$ nominal)**

	2017	2018	2019	2020
AMI single phase	504.13	473.37	435.70	404.36
AMI three phase	613.49	579.23	537.45	501.56
AMI three phase current transformer	1 205.84	1 150.56	1 097.61	1 047.95
Non AMI NMIs	43.18	45.04	46.97	48.99

Source: Powercor, Revised Regulatory Proposal 2016–2020, p. 463, Table 14.8.

Note: Exit fee is charged on a per National Meter Identifier basis.

<sup>49</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 460.

<sup>50</sup> Powercor, *Revised regulatory Proposal*, January 2016, p. 462.

## 16.3.3 Assessment Approach

### 16.3.3.1 Cost Allocation

For the preliminary decision we had regard to the wider regulatory context in determining the allocation of metering service costs, including key framework issues for Victorian metering in the 2016–20 regulatory control period, such as:

- the need to facilitate a smooth transition of governance under the Order to regulation under the modified NER
- the possibility of Victoria adopting the competitive metering framework sometime in the future.<sup>51</sup>

We considered that any cost allocation issues relating to metering costs would be best dealt with in the development of the ring-fencing guideline in accordance with a nationally consistent approach. On this basis, our preliminary decision allocated all costs formerly regulated under the Order to alternative control services.<sup>52</sup>

For the final decision we have reconsidered our preliminary decision approach to the allocation of metering costs between alternative control services and standard control services. We engaged Energy Market Consulting Associates to help develop a cost allocation approach that could be applied across the Victorian service providers.

Our revised approach to the allocation of AMI costs is set out in the discussion on Powercor's base opex – Appendix A of Attachment 7.

### 16.3.3.2 Annual metering charges

For alternative control services the AER has a greater discretion under the NER in making our assessment compared to standard control services. We have chosen to apply a streamlined version of a building block approach.

## Forecast capex

There are three categories of metering capex: remotely read interval meters, IT and communications. To assess remotely read interval meter capex, we reviewed unit rates and volumes.

In the preliminary decision we benchmarked the proposed meter hardware unit costs across the businesses. We considered this to be appropriate because the Victorian businesses all use the same six meter types and so the costs can be compared.<sup>53</sup>

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<sup>51</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, pp. 16-38, 16-39.

<sup>52</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, pp. 16-38, 16-39.

<sup>53</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-35.

We substituted unit costs based on the lowest forecast unit costs for each meter type submitted by a Victorian business in its proposal for the 2016–20 regulatory control period.<sup>54</sup>

For the final decision we have reconsidered our preliminary decision approach, taking account further submissions from the network businesses.

Submissions received suggested that any benchmarking should account for differences between the businesses reflecting their circumstances and the way each has contracted with third parties for the supply of meters. This included differences in meter design, meter volumes and exchange rates that effect meter costs expressed in Australian dollars. We conducted an assessment of the tendering processes each business had followed when entering into contracts with suppliers. Where we were satisfied that the applied process is prudent, based on a competitive tender arrangement, we accepted the proposed metering hardware unit costs.

We sought further information from Powercor on its meter tender and evaluation processes.<sup>55</sup>

We also reviewed our 2012–15 AMI budget and charges determinations.<sup>56</sup>

## Forecast opex

We considered Powercor's proposed metering opex by developing our own alternative forecast. To do this we used a top-down 'base–step–trend' approach. This is our preferred approach to assessing most opex categories.<sup>57</sup> In particular, we:

- used the "revealed costs" approach as the starting point and removed any non–recurrent expenditure
- in contrast to past metering decisions for non–Victorian distribution businesses, decided against the use of benchmarking
- adjusted for any step changes if we were satisfied that a prudent and efficient service provider would require them
- trended forward the base opex (plus any step changes) by considering the forecast changes in output, price and productivity.<sup>58</sup>

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<sup>54</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-39.

<sup>55</sup> AER Information Request #042, response from Powercor, dated 23 February 2016.

<sup>56</sup> The AER's AMI budget and charges determination 2012–15 can be found at [https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs?fj0=type%3Aacc%20aer%20ami%20charges&fj1=field\\_acc%20aer%20effective\\_date%3A2012](https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs?fj0=type%3Aacc%20aer%20ami%20charges&fj1=field_acc%20aer%20effective_date%3A2012)

<sup>57</sup> AER, *Better regulation: Expenditure forecast assessment guideline for distribution*, November 2013, p. 32.

<sup>58</sup> For a further discussion on the opex assessment approach, see; AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, pp. 16-35 to 16-37.

### 16.3.3.3 Exit fee

When calculating the exit fee required under the Order, the inputs we used were:

- our final decision on Powercor's opening metering RAB value as of 1 January 2016
- the forecast metering capex and opex which we have accepted in this final decision for Powercor's 2016–20 regulatory control period
- in relation to an administration component of the exit fee, our final decision on the real labour cost escalators applicable in Victoria.

We also had regard to the revenue and pricing principles that the distributors should be afforded full cost recovery (see also clause 7.2 of the Order).

### 16.3.4 Reasons for final decision

#### 16.3.4.1 Cost allocation

Our final decision does not accept the AMI cost allocation proposed by Powercor. Our final decision on the allocation between alternative control services and standard control services is set out in Table 16.4 above.

Our revised approach and reasons for the final decision on the allocation of AMI costs is set out in the discussion on the base opex – Appendix A of Attachment 7.

#### 16.3.4.2 Annual metering charges

##### Forecast capex

Our final decision approves \$45.1 million (\$2015) in capex for Powercor's alternative control metering services. This is equal to 86 per cent of Powercor's revised capex forecast. Table 16.9 sets out our final decision on each component making up Powercor's metering capex.

**Table 16.9 Final decision on Powercor's metering capex (\$2015)**

	Revised proposed	Approved
Remotely read interval meters	32.9	25.9
IT	4.3	4.1
Communications	15.4	15.1
Total	52.5	45.1

Source: AER analysis; Powercor, *Revised regulatory proposal 2016–20, Metering PTRM an exit fees*, January 2016, 'PTRM input' tab

## *Remotely read interval meters*

### **Meter hardware unit costs**

We accept Powercor's proposed meter hardware costs.

Powercor did not accept our preliminary decision on the meter hardware costs.<sup>59</sup>

For the final decision we have reconsidered our preliminary decision approach.

We accept that the approach adopted in the preliminary decision of applying the lowest forecast unit costs submitted by a Victorian distributor for each meter type was inappropriate. This approach did not take into account the businesses' conditions in procuring meters, including differing communications technology and volume assumptions. This lowest unit cost approach did not have sufficient regard to the differing network circumstances across the businesses and is not reflective of any inherent inefficiency. This led to the establishment of a comparison that was not based on a like-for-like benchmark.

Instead, we conducted an assessment of the tendering processes each business had followed when entering into contracts with suppliers. A review of the governance and procurement practices and procedures is a reasonable approach to assessing efficient costs where services are being sourced through a competitive tender in an open market. This approach is also consistent with the approach adopted for the procurement of meters for the smart meter rollout in Victoria under the Order. Where we were satisfied that the applied process is prudent, based on a competitive tender arrangement, we accepted the proposed metering hardware unit costs.

Powercor and CitiPower undertook a joint procurement process for the engagement of metering hardware providers for the AMI roll out program.<sup>60</sup> As a result of this tender process, Powercor appointed two metering providers, Landis & Gyr and Secure Meters, for its AMI roll out.

Having examined Powercor's tendering process for the procurement of metering hardware, we consider that the contracts have been determined on a competitively tendered basis and the meter unit costs represent competitively sourced market rates.

Our 2012–15 AMI budget and charges determination supports this.<sup>61</sup> Our consultants, Impaq Consulting also maintained that Powercor's vendor contracts had been let on a competitively tendered basis.<sup>62</sup>

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<sup>59</sup> Powercor, *Revised Regulatory Proposal*, January 2016, pp. 449–450.

<sup>60</sup> AER Information Request #042, response from Powercor, dated 23 February 2016, p. 1.

<sup>61</sup> AER *Final Determination—AMI budget and charges applications 2012–15*, 31 October 2011, p. 211; <http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/powercor-ami-budget-and-charges-determination-2012-15>

<sup>62</sup> Impaq Consulting, *Review of DNSP's AMI Budget Submissions for 2012 to 2015*, 20 July 2011, p. 80.

Powercor will continue to procure meters from its existing suppliers. We consider this to be reasonable in the circumstances. Running a further tender process for the supply of meters for the 2016–20 regulatory control period is unlikely to provide any additional value to customers given:

- the costs involved in undertaking a tender process are not insignificant
- the contract will be for a short term because metering contestability commences in Victoria on 1 December 2017
- the low volume of meters required.

We consider that the cost of engaging alternative vendors is likely to outweigh the benefits. In addition to the above limitations, even if Powercor is able to procure meters at a lower cost through an alternative vendor, it will incur other operating costs. In particular, end to end testing programs required for communication systems and data collection compliance in accordance with the mandated service levels.

### **Meter installation costs**

We do not accept Powercor's proposed meter installation costs.

We accept that meter faults do not necessarily occur during business hours and Powercor will incur back office costs associated with delivering its metering services. However, we do not accept Powercor's proposed time taken to install a replacement meter.

Powercor submitted that:

- the labour time taken to replace a meter is longer than a new connection, which we applied in the preliminary decision
- on-costs should be included in the labour rates
- meter replacements must take into account the fact that meter faults do not necessarily occur during business hours.<sup>63</sup>

Powercor submitted that the labour time taken to replace a meter is longer than a new connection because:

- travel time to a fault cannot be coordinated to maximise efficiencies. Fault calls are responded to reactively while new connections can be planned to minimise travel times
- they do not know the cause of the fault until arriving on the site, therefore they action a network fault response which involves sending a fault truck and crew to the site
- upon arriving on site, they need to ensure the site is safe, including isolating the supply point and replacing the service fuse

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<sup>63</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 450–451.

- following the completion of safety procedures, they need to identify the cause of the fault e.g. whether the fault is due to a faulty meter, faulty wiring or the meter board.

We maintain that the time taken to replace a meter should not be vastly different to the time taken to provide a new connection.

Whilst we accept that responses to fault calls are reactive and as a result travel would be inefficient compared to travel for planned works, the contributing factors submitted by Powercor are in respect of a network fault or emergency response, which is a broader task than just a meter replacement. Fault call outs deal with, amongst other things, the need to respond to installations with no power. In these situations there can be a number of reasons for no power at a premise. While a meter fault would be one of those reasons, it should not be a significant callout reason in itself.

A meter replacement is a capital cost generally considered on a needs basis, proven through a reasonable estimate of the volume requiring replacement i.e. meters or meter types that do not meet specification or are failing. Whereas network faults or emergency responses are fully funded, generally as a recurring standard control opex cost. Powercor should not conflate the two tasks.

The time taken to install a new connection would generally involve (and varying depending on the type of installation, for example overhead, underground or multi storey dwelling)– running service mains, installing service fuses, installing a meter, energising the installation, testing, appropriate record keeping and time travelled. A meter replacement on the other hand would generally involve (and varying depending on, for example, ease of access to service fuses, meter board access and whether its overhead or underground)–isolating the installation (removing the fuse), removing the old meter, installing the new meter, re-energising (replacing the fuse), testing, record keeping, and time travelled.

Given the tasks involved in meter replacement, we consider that the time taken to install a new connection is sufficient to cover a meter replacement.

Our final decision on the labour component of Powercor's metering replacement capex will follow our approach to ancillary network services for new metering connections. That is, we have used the same maximum labour rate for metering replacements which applies to ancillary network services new meter connections. The labour cost of replacing meters is recovered through the capex building block for alternative control metering; however, the cost of installing meters at new connections is recovered through separate ancillary service charges.

Table 16.10 sets out the ancillary network services new connection 'labour rates' and 'time taken' inputs which we have applied to the cost build-up of the labour component to metering replacements.

**Table 16.10 Meter replacement labour cost inputs per installation (\$2015)**

	Unit rate (\$2015)	Time taken (hours)	Cost per installation (\$2015)
Skilled electrical worker	124.51	2.10	261.47
Support staff	68.08	0.6	40.85
Total			302.32

Source: AER analysis.

We accept that not all meter replacements occur within business hours. To give effect to this, we have weighted the business hours and after hours 'skilled electrical worker'<sup>64</sup> unit rate to take into account 20 per cent of meter replacements occurring after hours.

We also accept that Powercor will incur back office costs associated with meter replacement and have included an administration component<sup>65</sup> to cover the cost of an office worker coordinating meter replacements. The administrative component for meter replacement is consistent with our approach adopted for new connections.

We do not accept Powercor's proposed 3.29 hours taken to undertake the meter replacement for the reasons stated above. We have applied a rate of 2.10 hours instead. This is consistent with the time taken for ancillary network services new connections, which we consider is sufficient to cover a meter replacement. The new connection service proposed by Powercor does not assume different installation times for different meter types, such as a multi-phase meter.

Table 16.11 sets out our final decision on Powercor's meter replacement installation costs.

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<sup>64</sup> We have applied our approved quoted service ancillary network services hourly labour rate for a skilled electrical worker set out in Appendix A.1, Table 16.14.

<sup>65</sup> We have applied our approved quoted service ancillary network services hourly labour rate for a support staff set out in Appendix A.1, Table 16.14.



**Table 16.11 Meter replacement installation costs (\$2015)**

	AER preliminary decision	Revised proposal	AER final decision
Meter replacement labour rate per hour (\$2015)	121.49	166.51	124.51
Average labour time to replace meter (hours)	2.10	3.29	2.10
Average labour cost to replace a meter (\$2015) (direct cost)	255.13	548.41	261.47
Support staff	-	- <sup>(a)</sup>	40.85
Total	255.13	548.41	302.32

Source: Powercor Revised regulatory proposal 2016–20, January 2016, p. 451 and AER analysis.

(a) Powercor's revised proposal disputed the exclusion of on-costs from its labour rates but did not propose an alternative cost for this component in its metering model; CP Public MOD 1.2 – CP Metering Capex & Opex – public version.

### Meter volumes

Our final decision is to accept Powercor's meter volumes.

We accepted Powercor's metering volumes in our preliminary decision.<sup>66</sup> We also indicated that we may revisit forecast metering volumes in the final decision if more information becomes available. We did this because at the time of the release of our preliminary decision the AEMC's final rule determination on metering contestability had not been finalised. The implementation timeframe and whether this would apply to Victoria remained uncertain.

Powercor has revised its metering volumes<sup>67</sup> to take into account that metering contestability is now proposed to be introduced in Victoria on 1 December 2017, in accordance with the AEMC's final rule determination<sup>68</sup>. This has resulted in a modest increase in the number of meter replacements to account for the delay in metering contestability to 1 December 2017.

### IT/Communications

Our final decision is to accept Powercor's IT and communications capex.

<sup>66</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-40.

<sup>67</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 449.

<sup>68</sup> AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

We accepted Powercor's IT and communications capex in our preliminary decision.<sup>69</sup>

Powercor has accepted our IT preliminary decision but updated its communications capex forecast to include:

- new metering connections, reflecting that the commencement date for metering contestability is now 1 December 2017
- updated foreign exchange rate forecasts.<sup>70</sup>

We consider that the revised forecasts are reasonable. The updated forecasts reflect the extension of time for the commencement of metering contestability and recent observed foreign exchange rate movements.

## Forecast opex

Our final decision approves \$82.2 million (\$2015) in alternative control metering opex for Powercor's 2016–20 regulatory control period. This is more than Powercor's revised forecast of \$76.3 million (\$2015).

Our final decision approves more opex than Powercor included in its alternative control metering proposal because of our approach to cost allocation (see section 16.3.1.1). Compared to Powercor's revised proposal, we have allocated a greater proportion of costs to alternative control metering services. This leads to a higher base, or 'starting point', from which to consider Powercor's opex. The corollary of this is that we have allocated less opex to Powercor's standard control network services than proposed. This leads to a lower base than Powercor proposed for standard control network services.

## Base

We determined Powercor's base annual opex to be \$15.6 million (\$2015).

Table 16.12 sets out the components of our final decision regarding Powercor's base opex for the 2016–20 regulatory control period. It shows that the key difference from Powercor's revised proposal is that our final decision reallocates less of Powercor's base opex to standard control network services. By doing this, we have approved a higher base than Powercor forecast in its revised proposal. We explain our cost allocation approach between standard and alternative control metering services in section 16.3.1.1.

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<sup>69</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-40.

<sup>70</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 453–454.

**Table 16.12 AER's assessment of Powercor's base (\$million, 2015)**

Cost category	Revised proposal	Final decision
<u>Raw base</u>		
2014 reported opex	18.9	18.9
<u>Non-recurrent cost</u>		
Adjustment for one-off costs	(0.9) <sup>(a)</sup>	(0.9) <sup>(a)</sup>
<u>Reallocation of costs</u>		
Costs moved to standard control services	(4.9)	(3.2)
<u>Adjusted base</u>		
Base opex – including corporate overheads	13.9 <sup>(b)</sup>	15.6 <sup>(b)</sup>

Source: AER analysis; Powercor, *Revised Regulatory Proposal 2016–2020, Metering capex and opex model (Public)*, January 2016; Powercor, AER information request #050, 24 March 2016.

(a) For presentation purposes, the adjustment shown is an average of five years of costs.

(b) For presentation purposes, the adjusted base shown is an average of five years of expenditure.

Our determination on Powercor's base annual opex applied the revealed costs approach. We also had regard to our final decision on Powercor's allocation of opex between standard and alternative control metering services.

Using the revealed costs approach, we selected Powercor's actual opex in 2014 as our starting point. In 2014, Powercor's actual opex was \$18.9 million (\$2015). We selected Powercor's actual metering opex in 2014 for two reasons. First, it is the last completed year from which we have audited accounts on Powercor's metering opex. Second, the costs incurred in 2014 should resemble 'business as usual' opex for metering in the forthcoming 2016–20 regulatory control period. This is because Powercor had been set a target to have completed its rollout of AMI before the commencement of the 2014 year.<sup>71</sup>

The next step in our assessment of Powercor's base involved considering whether we should make any adjustments for non-recurrent expenditure. In developing its proposal, Powercor removed certain costs from its base.<sup>72</sup> We consider these adjustments to be sufficient to remove non-recurrent expenditure. Table 16.12 sets out the adjustments and their magnitude. We have applied them to our assessment of Powercor's base level of opex.

We consider that following the removal of non-recurrent expenditure, Powercor's actual opex in 2014 does not contain material inefficiencies. We reached this

<sup>71</sup> AMI Cost Recovery Order, cl. 14.1.

<sup>72</sup> Powercor, *Revised Regulatory Proposal 2016–2020, Metering capex and opex model (Public)*, January 2016, 'Opex' tab.

conclusion on the basis that the Victorian distribution businesses are generally efficient. This is compared to their counterparts in other regions of the national electricity market.<sup>73</sup> We have therefore decided not to make an efficiency adjustment to the base level of opex.

The final step we took in determining Powercor's base was a cost allocation process between standard and alternative control metering services. This process is outlined in section 16.3.1.1 above. After applying our approach to cost allocation, we determined Powercor's base opex to be \$15.6 million (\$2015).<sup>74</sup>

### **Step**

We affirm our preliminary decision to accept Powercor's proposed step change associated with the testing of current transformer (CT) meters.<sup>75</sup> These are three phase meters which are generally installed for small commercial customers.<sup>76</sup>

We will only accept a proposed step change if it is associated with a new regulatory obligation or a capex/opex trade-off.<sup>77</sup> This position is consistent with our Expenditure forecast assessment guideline.<sup>78</sup> We have accepted Powercor's proposed step change because it relates to a new regulatory obligation. Specifically clause 7.6 and schedule 7.3 of the NER require Powercor to test a set of newly installed CT meters in the 2016–20 regulatory control period.

### **Trend**

We trended forward the base over the 2016–20 regulatory control period. When trending forward the base we applied an opex rate of change. This comprised of a real price growth adjustment for labour but not an output growth adjustment.

With respect to real price growth, our final decision approves escalation for labour. We have not, however, accepted Powercor's proposal for real price escalation to be applied to materials or contracts.

We accept Powercor's proposal that wages are likely to grow at a rate that does not reflect the consumer price index (CPI). Our final decision accepts that a labour price escalator should be applied to Powercor's opex. By contrast, we do not accept that materials and contract prices will move at a rate that does not reasonably reflect CPI and hence we have not applied escalators to them.

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<sup>73</sup> See attachment 7 to this final decision.

<sup>74</sup> See Table 16.12 above.

<sup>75</sup> AER, *Preliminary Decision, Powercor distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-43.

<sup>76</sup> Powercor, *Regulatory Proposal 2016–2020*, April 2015, p. 455.

<sup>77</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

<sup>78</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

When escalating Powercor's opex for labour price growth, we have applied the same escalators which we have determined for standard control network services. We consider this to be reasonable because network and metering services belong to the same industry. Labour price growth in metering should therefore be the same as in network services.

We did not apply an output growth adjustment in our preliminary decision. Powercor accepted this aspect of our preliminary decision in its revised proposal.<sup>79</sup> We affirm our preliminary decision, and when trending forward Powercor base have not applied an adjustment for output growth.

#### **16.3.4.3 Metering exit fee**

Our final decision does not accept Powercor's proposed exit fee.

Powercor's proposed exit fee includes an administrative and capital cost component. The administrative component recovers clerical costs associated with a customer leaving Powercor's metering service. This will be possible when metering contestability is introduced in 2017. The capital component recovers the remaining written down value of metering assets corresponding to the customer leaving Powercor's service. This is derived from the opening metering asset base which we approve for Powercor in this final decision.

Our final decision accepts the administrative cost component of Powercor's proposed exit fees. But after adjusting for actual CPI, we have not accepted Powercor's proposed opening metering asset base. Our final decision accepts an opening metering asset base value as of 1 January 2016 of \$332.1 million (\$ nominal) rather than Powercor's proposed \$333.4 million (\$ nominal). In terms of its exit fee charges, this leads to a lower capital component.

Our administrative cost component of the exit fee is potentially in contrast with the decisions we made during the New South Wales, Queensland, South Australia and the Australian Capital Territory determinations in April 2015. Specifically, we rejected the administrative costs those distributors proposed in the case of removing a meter.<sup>80</sup> While we found that the costs were not sufficiently material in those jurisdictions, the Order applicable to the Victorian distribution businesses requires that we set an exit fee; and thus we have accepted the inclusion of an administrative cost component. We have nonetheless adjusted it for our final decision on the labour cost escalators applicable in Victoria in the 2016–20 regulatory control period.

Our substitute exit fees are set out in section 16.3.1.4.

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<sup>79</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 456.

<sup>80</sup> The reasons for this decision are set out in, for example; AER, *Preliminary Decision, Energex distribution determination 2015–16 to 2019–20, Attachment 16 – Alternative control services*, November 2014, p. 16-52.

# A Ancillary network services prices

## A.1 Ancillary network services

**Table 16.13 Fee based ancillary network services prices for 2016, final decision (\$2016)**

Fee based service	Hours	Final decision price
Meter investigation	Business hours	385.61
	After hours	441.76
Meter accuracy test—single phase	Business hours	425.74
	After hours	488.89
Meter accuracy test—single phase additional meter	Business hours	178.66
Meter accuracy test—multi phase	Business hours	512.94
	After hours	591.30
Meter accuracy test—multi phase additional meter	Business hours	325.78
Meter accuracy test—CT	Business hours	600.68
	After hours	694.34
Reconnections (incl. customer transfer)	Business hours	50.87
	After hours	224.71
Reconnections (same day)	Business hours	82.91
Disconnection	Business hours	54.08
Disconnection for non payment	Business hours	54.08
Special reading	Business hours	44.67
Access to meter data	Business hours	45.38
Service truck visit	Business hours	607.61
	After hours	730.22
Wasted truck visit	Business hours	334.22
	After hours	386.17
Remote meter reconfiguration	Business hours	52.95
Remote re-energisation	Business hours	9.99
Remote de-energisation	Business hours	9.99
<b>New connection responsible for metering</b>		
Single phase	Business hours	486.74

Fee based service	Hours	Final decision price
	After hours	545.22
Multi phase DC	Business hours	602.81
	After hours	661.58
Multi phase CT	Business hours	2,360.27
	After hours	2,927.31
<b>New connection not responsible for metering</b>		
Single phase	Business hours	455.26
	After hours	508.55
Multi phase DC	Business hours	571.32
	After hours	624.61
Multi phase CT	Business hours	2,018.65
	After hours	2,290.12

Source: Powercor, 2016 pricing proposal, 19 November 2015, pp. 82–83.

**Table 16.14 Quoted service ancillary network services hourly labour rates for 2016, final decision (\$2016)**

Service description	Hours	Final decision hourly labour rates
Skilled electrical worker	Business hours	122.18
	After hours	143.49
Support staff	Business hours	69.10
	After hours	N/A

Source: Powercor, 2016 pricing proposal, 19 November 2015, p. 85.

## B Annual metering charges unders and overs account

To demonstrate compliance with the distribution determination applicable to it during the 2016–20 regulatory control period, Powercor must maintain an annual metering charges unders and overs account in its annual pricing proposal.

Powercor must provide the amounts for the following entries in their annual metering charges unders and overs account for the most recently completed regulatory year (t–2), the current regulatory year (t–1) and the next regulatory year (t):

1. An opening balance for year t–2, year t–1 and year t;
2. An interest charge for one year on the opening balance for each regulatory year (t–2, t–1 and t). These adjustments are to be calculated using the respective nominal weighted average cost of capital (WACC) for each intervening year between regulatory year t–2 and year t.<sup>81</sup> The WACC applied for each year will be that approved by the AER for the relevant year;
3. The amount of revenue recovered from metering charges in respect of that year, less the total annual revenue for the year in question;
4. An adjustment to the net amount in item 3 by six months of interest. These adjustments are to be calculated using the approved nominal WACC;
5. The total sum of items 1–4 to derive the closing balance for each year.

Powercor must provide details of calculations in the format set out in Table 16.15. Amounts provided for the most recently completed regulatory year (t–2) must be audited. Amounts provided for the current regulatory year (t–1) will be regarded as an estimate. Amounts for the next regulatory year (t) will be regarded as a forecast.

In proposing variations to the amount and structure of annual metering charges, Powercor is expected to achieve a closing balance as close to zero as practicable in its annual metering charges unders and overs account in each forecast year in its annual pricing proposals during the 2016–20 regulatory control period.

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<sup>81</sup> The WACC for each year will be that approved by the AER for the respective year and as calculated as set out in figure 14.1 of Attachment 14 to this final decision. .



**Table 16.15 Example calculation of annual metering charges unders and overs account (\$'000, nominal)**

	Year t-2 (actual)	Year t-1 (estimate)	Year t (forecast)
<b>(A) Revenue from annual metering charges</b>	<b>8 449</b>	<b>7 389</b>	<b>6 460</b>
<b>(B) Less TARM for regulatory year =</b>	<b>7 366</b>	<b>7 422</b>	<b>7 573</b>
+ Annual revenue requirement (AR <sub>t</sub> )	7 349	7 412	7 559
+ T factor (T <sub>t</sub> ) – true-ups relating to the AMI–Order in Council	17	10	14
<b>(A minus B) Under/over recovery of revenue for regulatory year</b>	<b>1 083</b>	<b>-33</b>	<b>-1 113<sup>a</sup></b>
<b>Annual metering charges unders and overs account</b>			
Nominal WACC (per cent)	5.00%	5.50%	6.00%
Opening balance	-50	1 057 <sup>b</sup>	1 081
Interest on opening balance	-3	58	65
Under/over recovery of revenue for regulatory year	1 083	-33	-1 113 <sup>b</sup>
Interest on under/over recovery for regulatory year	27	-1	-33
<b>Closing balance</b>	<b>1 057</b>	<b>1 081</b>	<b>0<sup>c</sup></b>

Notes: (a) Approved annual metering charges revenue under/over recovery for regulatory year t. This is the B<sub>t</sub> parameter in the annual metering charges revenue cap formula.  
(b) Opening balance is the previous year's closing balance.  
(c) Powercor is expected to achieve a closing balance as close to zero as practicable in its annual metering charges unders and overs account in each forecast year in its annual pricing proposals in the 2016–20 regulatory control period.