



FINAL DECISION
United Energy 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 United Energy'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

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – f-factor scheme

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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 United Energy 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'.¹

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

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 United Energy's revised proposal for ancillary network services. Most of the labour inputs United Energy applied in developing its fee based service prices do not exceed maximum total labour rates which we consider efficient. We also

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

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

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

accept United Energy's proposed total labour rates for quoted services, as they do not exceed maximum total labour rates which we consider efficient.

However, we do not accept United Energy's revised proposal prices for some connection services and temporary supplies. Our final decision maintains our preliminary decision labour inputs and times taken to perform these services.

Our final decision prices are the same as those we approved in United Energy's 2016 pricing proposal.⁴ We note our preliminary decision approved United Energy's prices for 2016 in \$2015 terms and noted that these were to be escalated into \$2016 terms in United Energy's 2016 pricing proposal using the approved CPI adjustment.⁵ We approved United Energy's 2016 pricing proposal in December 2015.⁶

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.

Our final decision has also updated the labour price growth to reflect the most up-to-date forecast. Our final decision labour price growth is set out in Table 16.1 and is discussed in attachment 7—operating expenditure.

Forms 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,⁷ and our preliminary decision.⁸ United Energy accepted these formulas in its revised regulatory proposal.⁹

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

⁴ United Energy, *2016 pricing proposal*, 24 November 2016, pp. 64–67.

⁵ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16: Alternative control services*, October 2015, pp. 46–48.

⁶ United Energy, *2016 pricing proposal*, 24 November 2016.

⁷ AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 July 2016*, 24 October 2014, pp. 92–93.

⁸ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, p. 16-7.

⁹ United Energy, *2016 to 20 revised regulatory proposal*, 6 January 2016, p. 5. (United Energy, *Revised regulatory proposal*, 6 January 2016).

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 Cities¹⁰ 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 16.1.¹¹

¹⁰ 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.

¹¹ 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.¹² Figure 16.2 sets out the price cap formula and Table 16.13 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 Cities¹³ 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.

¹² AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 July 2016*, 24 October 2014, p. 89.

¹³ 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 16.1.¹⁴

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 United Energy's revised proposal

United Energy accepted our preliminary decision labour rates for quoted services.¹⁵ It also accepted our preliminary decision on fee based services, except for:

- new connections (business hours and after hours), and
- temporary supplies (business hours and after hours).¹⁶

United Energy submitted that for new connections and temporary supplies, our preliminary decision failed to take into account that these services are two person functions.¹⁷

16.1.3 Assessment approach

Our final decision assessment approach is the same as our preliminary decision. We have also considered United Energy's revised regulatory proposal.¹⁸

Our preliminary decision undertook a detailed assessment of United Energy'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', analysis¹⁹
- since labour is the key input in determining an efficient level of prices for ancillary network services, we focused on comparing United Energy's proposed total labour rates against our developed maximum total labour rates

¹⁴ The X factors applied in this formula adjust for annual labour price growth.

¹⁵ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

¹⁶ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

¹⁷ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

¹⁸ United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 1–206.

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

- the other key inputs, being:
 - proposed times taken to perform the service, and
 - contractor rates.

As per section 16.1.4.2 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 United 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.²⁰

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.

Where a distributor’s proposed total labour rates exceeded our maximum total labour rates—which we consider are efficient—we applied our maximum total labour rates to determine ancillary network service charges.

As a further check of our analysis, we benchmarked components of the Victorian distributors’ proposed labour costs against one another.

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

²⁰ NEL, ss. 7A and 16.

16.1.4 Reasons for final decision

We do not accept United Energy's revised proposal on ancillary network services.²¹ Our preliminary decision adjusted United Energy's unit cost inputs for these services based on:

- our maximum efficient total labour rates, and
- efficient times taken to perform these services.

Our reasons for maintaining our preliminary decision are explained in section 16.1.4.1.

United Energy reflected our preliminary decision changes in its 2016 pricing proposal, which we approved in December 2015.²² We have reproduced these prices and rates in Table 16.12 and Table 16.13 in appendix A.1—they are our final decision prices for United Energy's ancillary network services.

16.1.4.1 Contractor rates—new connections and temporary supplies

We maintain our preliminary decision that United Energy's proposed average unit contractor rates for the provision of its new connection and temporary supplies services exceed efficient maximum total labour rates. Therefore, we do not accept United Energy's revised proposal.

Our preliminary decision accepted the materials and administrative labour components of these services. However, we did not accept the proposed unit rates for the on-site (or field) component.²³ Our benchmarking demonstrated these unit rates exceeded the maximum total labour rates which we consider are efficient. Therefore, we substituted in our maximum total labour rates into United Energy's cost build-up method to establish efficient prices for these services.²⁴

As the average unit contractor rates in United Energy's cost build-up method were in dollar values only, our preliminary decision benchmarked them against a build-up of labour rates and times taken to perform the service to determine their efficiency.²⁵ This approach is prudent in determining efficiency as labour rates and times taken to perform the service are the key inputs in establishing the prices for ancillary network services.²⁶

²¹ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

²² United Energy, *United Energy 2016 pricing proposal*, November 2015, pp. 64–67.

²³ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, pp. 12–13.

²⁴ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, pp. 6–7, 13–14.

²⁵ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, pp. 12–14.

²⁶ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, pp. 11–19.

For our assessment, we developed maximum total labour rates that will provide United Energy with a reasonable opportunity to recover at least the efficient costs it incurs in providing these services.²⁷ The maximum total labour rates are set out in Table 16.2.

We also developed benchmark times taken to perform the service by comparing the times taken by other Victorian distributors.²⁸ We consider the benchmark time taken demonstrates the efficient time taken by distributors to perform the service.

Our analysis demonstrated that the Victorian distributors undertake the on-site component of connection services in a time of approximately two hours or less—including travel time.²⁹ Included in this analysis were the large rural networks of Powercor and AusNet Services which have increased travel times compared to the other Victorian distributors. Therefore, we considered a benchmark time of two hours is a reasonable estimate of time required to perform the on-site component.

To determine the efficiency of United Energy's unit rates, we divided the applicable labour component of the proposed unit rates by our benchmark time of two hours to deduce the hourly labour rates. Our analysis demonstrated that the hourly rates for United Energy's connection services exceeded our maximum total labour rates. As we consider our maximum total labour rates are efficient for providing these services, we did not accept United Energy's proposed unit rates for these services.

As United Energy applied the same unit rates and cost-build up approach to derive prices for its temporary supply services, our preliminary decision did not accept these unit rates and substituted in our maximum total labour rates.³⁰

In response, United Energy considered that our preliminary decision analysis had failed to consider the number of people needed to perform new connection or temporary supplies services.³¹ United Energy posited that our approach was based on the premise that these services are undertaken by one person for two hours. However, United Energy noted that this is a two person function.

Therefore United Energy considered that by applying two people into the preliminary decision benchmarking approach—two people for two hours—then its proposed costs for these services should be accepted as they are below the recalculated benchmark.³²

However, we note our benchmark times taken are based on the efficient total time (the number of labour hours, including travel time) taken by distributors to perform the

²⁷ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, pp. 14–19.

²⁸ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, p. 13.

²⁹ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, p. 13.

³⁰ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, p. 14.

³¹ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

³² United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

service and not the number of people involved.³³ For example, a benchmark time of two hours could be performed by:

- one person in two hours, or
- two people in one hour, or
- four people in half an hour.

Using United Energy's revised proposal consideration would mean the benchmark time taken would be four hours. We consider this would be an overstatement of the time given those proposed by the other Victorian distributors.

We note that one Victorian distributor considered it would take two people to complete the on-site component in a total of one hour—effectively half an hour for each person. While three of the Victorian distributors proposed two people would undertake the on-site component—including travel time—in effectively one hour each. Therefore, we do not accept United Energy's consideration that we failed to consider the number of people needed to perform new connection or temporary supplies services.³⁴

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 4.82 per cent instead of the proposed 7.95 per cent

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.

³³ AER, *Preliminary decision: United Energy distribution determination 2016 to 2020: Attachment 16 – Alternative control services*, October 2015, p. 16–13.

³⁴ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 114.

16.2.2 United Energy's revised proposal

United Energy did not accept the AER's preliminary decision WACC and proposed the addition of frangible poles to public lighting charges but has accepted all other aspects of the AER's preliminary decision.³⁵

16.2.3 Assessment approach

Our final decision assessment approach is the same as our preliminary decision. We have also considered United Energy's revised regulatory proposal.³⁶

Our preliminary decision undertook a detailed assessment of United Energy's initial proposal by focussing on the key inputs in determining charges 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.³⁷

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.³⁸

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.

We accept the addition of frangible poles into public lighting charges in response to VicRoads request to distributors. This will allow distributors to more efficiently replace these poles and meet VicRoads needs.

We accept the materials prices proposed. The Greenhouse Alliance submission argued that the proposed materials prices are in some instances excessive.³⁹ 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

³⁵ United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 115–117.

³⁶ United Energy, *Revised regulatory proposal*, 6 January 2016.

³⁷ Essential Services Commission of Victoria, *Review of Public Lighting Excluded Services, August 2004 Final Decision*, pp. 70–73.

³⁸ AER, *2011-15 Victorian Electricity Distribution, Final Decision*, p. 836.

³⁹ Greenhouse Alliance, *Submission to AER Preliminary Decision*, 6 January 2016, p.2.

Alliance recommends distributors select the cheapest face value material prices available. The least cost purchase price is not necessarily the most effective or efficient 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 United Energy 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 United Energy has sought to procure public lighting cost inputs, and recovered them through the public lighting charges model.

We do not accept the need for United Energy's proposed true up mechanism and consider that updating preliminary decision charges for the final decision charges and adjusting these prices in the annual pricing approval process will ensure efficient revenue recovery for public lighting services. This is consistent with our decision not to accept Jemena's proposed true up mechanism for alternative control services.

Final decision charges for each light type are set out in Table 16.3.

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 | 52.05 | 54.76 | 58.49 | 61.97 | 65.71 |
| Sodium High Pressure 150 watt | 66.68 | 71.96 | 78.01 | 80.50 | 84.86 |
| Sodium High Pressure 250 watt | 68.32 | 73.71 | 74.72 | 82.35 | 86.78 |
| Fluorescent 2x20 watt | 67.15 | 70.64 | 75.45 | 79.93 | 84.76 |
| Fluorescent 3x20 watt | 67.15 | 70.64 | 75.45 | 79.93 | 84.76 |
| Mercury Vapour 50 watt | 77.04 | 81.04 | 86.56 | 91.71 | 97.25 |
| Mercury Vapour 125 watt | 77.04 | 81.04 | 86.56 | 91.71 | 97.25 |
| Mercury Vapour 250 watt | 62.17 | 67.07 | 67.99 | 74.94 | 78.97 |
| Mercury Vapour 400 watt | 86.09 | 92.87 | 94.15 | 103.76 | 109.34 |
| Mercury Vapour 700 watt | 86.09 | 92.87 | 94.15 | 103.76 | 109.34 |
| Sodium High Pressure 70 watt | 113.99 | 119.92 | 128.09 | 135.70 | 143.90 |
| Sodium High Pressure 100 watt | 73.34 | 79.15 | 85.81 | 88.55 | 93.34 |
| Sodium High Pressure 400 watt | 86.09 | 92.87 | 94.15 | 103.76 | 109.34 |
| Metal Halide 70 watt | 90.01 | 97.14 | 105.31 | 108.67 | 114.56 |
| Metal Halide 100 watt | 90.01 | 97.14 | 105.31 | 108.67 | 114.56 |
| Metal Halide 150 watt | 90.01 | 97.14 | 105.31 | 108.67 | 114.56 |
| Metal Halide 250 watt | 92.24 | 99.50 | 100.87 | 111.17 | 117.15 |
| Metal Halide 400 watt | 92.24 | 99.50 | 100.87 | 111.17 | 117.15 |
| T5 2X14W | 36.76 | 34.91 | 33.60 | 32.66 | 32.07 |
| Twin 24w Fluorescent | 36.76 | 34.91 | 33.60 | 32.66 | 32.07 |

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|--------------------|-------|-------|-------|-------|-------|
| Compact Fluoro 32W | 36.76 | 34.91 | 33.60 | 32.66 | 32.07 |
| Compact Fluoro 42W | 36.76 | 34.91 | 33.60 | 32.66 | 32.07 |

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 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.⁴⁰ 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.⁴¹ 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 2015.⁴² For jurisdictions that are part of the national metering framework, the new rules will take effect from 1 December 2017.⁴³ 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,

⁴⁰ AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p. 48.

⁴¹ 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.

⁴² AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

⁴³ AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

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.

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 United Energy. 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 - United Energy's allocation of AMI IT and Comms (% allocated to ACS and SCS)

| | Percentage allocated to ACS | Percentage allocated to SCS |
|--------------------------|-----------------------------|-----------------------------|
| Initial proposal | 0 | 100 |
| AER preliminary decision | 100 | 0 |
| Revised proposal | 21 | 79 |
| AER final decision | 32 | 68 |

Source: AER analysis

16.3.1.2 Annual metering charges

Our final decision accepts a total revenue requirement of \$232.1 million (\$ nominal) over the 2016–20 regulatory control period for metering services. It includes the following building blocks:

- forecast capex of \$13.7 million (\$2015), amounting to 100 percent of United Energy's proposal

- forecast opex of \$61.9 million (\$2015), which due to a change in cost allocation is higher than United Energy's revised proposal of \$52.9 million (\$2015)
- after updating for actual CPI, accepts an opening metering regulatory asset base as at 1 January 2016 of \$212.3 million (\$ nominal)
- with respect to depreciation, standard asset lives of 15 years for metering assets and 7 years for communications, IT and other metering 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 | | 23.8 | 25.4 | 26.9 | 18.4 | 15.8 |
| Return on capital | | 13.5 | 12.3 | 10.9 | 9.3 | 8.3 |
| Opex ^a | | 12.6 | 13.0 | 13.3 | 13.7 | 14.1 |
| Tax | | 0.0 | 0.0 | 0.0 | 0.0 | 2.0 |
| Unsmoothed revenue requirement | | 49.9 | 50.7 | 51.1 | 41.4 | 40.2 |
| X factor (%) ^b | | 41.82 | 30.65 | 5.50 | 5.50 | 5.50 |
| Smoothed revenue requirement | 105.4 | 62.7 | 44.5 | 43.1 | 41.6 | 40.2 |

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 United Energy'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 substantial decrease in prices in 2016 as a consequence of the large positive X factor we set in our preliminary decision. Under the CPI–X framework a positive X factor represents a real decrease in revenue. This will then be followed by another significant decrease in prices as a result of the large positive X factor we have set for

2017 in this final decision. Our revenue smoothing approach then applies further, but relatively more modest, decreases in prices in the outer years of the 2016–20 regulatory control period.

There are two key drivers effecting our final decision on United Energy's revenue requirement, and hence its price path for metering services. The first is United Energy 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 United Energy was rolling out its advanced metering infrastructure. The other key driver is a reallocation of a proportion of United Energy's operating costs. In our preliminary decision, we allocated all of United Energy'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 United Energy'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.⁴⁴ 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.

We do not accept United Energy's proposal to include an additional factor to adjust revenues in the event of the Victorian Government extending the existing derogation on metering competition.⁴⁵ As set out in our final decision Attachment 15, the pass through provisions of the NER will also apply to alternative control services. Therefore, a separate mechanism is not required in the annual metering charges revenue cap formula.

Under a revenue cap, United Energy'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 $t-1$.⁴⁶

⁴⁴ AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 July 2016*, 24 October 2014, pp. 89–93.

⁴⁵ United Energy, *2016 to 2020 Revised regulatory control proposal*, 6 January 2016, pp. 112–113.

⁴⁶ 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.

We have made this change to be consistent with the approach applied for the distribution use of system charges unders and overs account.⁴⁷

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.

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.

⁴⁷ Our final distribution use of system unders and overs account is discussed in attachment 14 – Control mechanisms.

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.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities⁴⁸ 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.

Figure 16.4 Side constraints

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

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.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities⁴⁹ 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

⁴⁸ 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.

⁴⁹ If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the 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 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.

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 United Energy.⁵⁰ The exit fees we have accepted in this final decision are set out in Table 16.6.

⁵⁰ NER, cl. 11.17.6.

Table 16.6 Final determination on United Energy's exit fees (\$ nominal)

| Meter category | 2016 | 2017 | 2018 | 2019 | 2020 |
|--|--------|--------|--------|--------|--------|
| Single phase single element meter | 459.33 | 428.66 | 397.56 | 371.36 | 535.64 |
| Single phase single element meter with contactor | 458.68 | 430.80 | 402.25 | 378.75 | 363.91 |
| Three phase direct connected meter | 512.97 | 479.56 | 447.49 | 420.21 | 401.39 |
| Three phase current transformer connected meter | 682.02 | 636.71 | 592.56 | 553.43 | 523.36 |

Source: AER analysis.

16.3.1.5 Type 7 meters

Our preliminary decision accepted United Energy's proposed type 7 meter charges.⁵¹ United Energy accepted our preliminary decision.⁵² The type 7 metering services charge are set out in Table 16.7 below. This charge will be subject to the price cap formula specified in Figure 16.1 above.

Table 16.7 AER final decision type 7 metering services (\$2016)

| Service | Final decision price (per light) |
|-------------------------|----------------------------------|
| Type 7 metering service | 1.29 |

Source: AER analysis; United Energy, *Alternative Control Services—Fee-based and quoted alternative control services 2016–20*, 30 April 2015, pp. 12–13.

16.3.2 United Energy'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

⁵¹ AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-32.

⁵² United Energy, *Revised regulatory proposal 2016–20*, January 2016, p. 111.

through alternative control services and we reallocated United Energy's metering costs from standard control services to alternative control.⁵³

United Energy has maintained its proposal that a portion of the metering costs should be allocated to standard control services.⁵⁴

16.3.2.2 Annual metering charges

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

- applied the general pricing structure set out in our preliminary decision
- submitted a revised capex of \$13.7 million for annual metering charges,⁵⁵ compared to the AER's preliminary decision accepting \$13.5 million (\$2015)⁵⁶
- submitted a revised opex of \$52.9 million for annual metering charges⁵⁷, compared to the AER's preliminary decision accepting \$109.1 million (\$2015)⁵⁸
- accepted our preliminary decision of an opening metering asset base (MAB) value as of 1 January 2016 of \$213.2 million (\$nominal).⁵⁹
- with respect to depreciation, standard asset lives of 15 years for metering assets and 7 years for communications, IT and other metering assets.⁶⁰

United Energy's revised proposal annual revenue requirement for the 2016–20 regulatory control period is set out in Table 16.8 below.

⁵³ AER, Preliminary Decision, *United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-27.

⁵⁴ United Energy, Revised regulatory proposal 2016–20, January 2016, pp. 104–107.

⁵⁵ United Energy, Revised regulatory proposal 2016–20, January 2016, p. 101.

⁵⁶ AER, Preliminary Decision, *United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-27.

⁵⁷ United Energy, Revised regulatory proposal 2016–20, Metering PTRM and exit fees, January 2016, 'PTRM input' tab.

⁵⁸ AER, Preliminary Decision, *United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-27.

⁵⁹ United Energy, Revised regulatory proposal 2016–20, January 2016, p. 108.

⁶⁰ United Energy, Revised regulatory proposal 2016–20, Metering PTRM an exit fees, January 2016, 'PTRM input' tab.

Table 16.8 Proposed metering annual revenue requirement (\$ nominal)

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|--------------------------------|-------|-------|------|------|------|
| Depreciation | 24.5 | 25.9 | 27.5 | 18.7 | 15.9 |
| Return on capital | 18.6 | 16.7 | 14.6 | 12.0 | 10.3 |
| Opex | 10.7 | 11.1 | 11.3 | 11.7 | 12.0 |
| Tax | 0.0 | 0.0 | 0.0 | 1.4 | 4.4 |
| Unsmoothed revenue requirement | 53.7 | 53.6 | 53.4 | 43.7 | 42.5 |
| X-factor (%) | 41.92 | 29.59 | 0.0 | 0.0 | 0.46 |
| Smoothed revenue requirement | 62.4 | 44.8 | 45.7 | 46.7 | 47.4 |

Source: United Energy, *Revised regulatory proposal 2016–20, Metering PTRM & Exit fees*, January 2016, 'Revenue summary' tab.

16.3.2.3 Metering exit fee

United Energy has updated the exit fees to reflect its revised capex forecast, cost of capital and included an administrative cost component omitted from the initial regulatory proposal.⁶¹ The revised proposal meter exit fees are set out in Table 16.9 below.

⁶¹ United Energy, *2016 to 2020 Revised Regulatory Proposal*, January 2016, p. 110.

Table 16.9 United Energy revised proposal meter exit fees (\$ nominal)

| Meter category | 2016 | 2017 | 2018 | 2019 | 2020 |
|--|--------|--------|--------|--------|--------|
| Single phase single element meter | 458.90 | 427.70 | 395.52 | 366.47 | 348.06 |
| Single phase single element meter with contactor | 458.25 | 429.83 | 400.18 | 373.80 | 358.22 |
| Three phase direct connected meter | 512.60 | 478.50 | 445.21 | 414.94 | 395.29 |
| Three phase current transformer connected meter | 681.82 | 635.35 | 589.57 | 547.10 | 515.93 |

Source: AER analysis; United Energy, *2016 to 2020 Revised Regulatory Proposal*, January 2016, p. 111.

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.⁶²

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.⁶³

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.

⁶² AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, pp. 16-38, 16-39.

⁶³ AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-39.

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

16.3.3.2 Annual metering charges

As an alternative control service, 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.⁶⁴

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.⁶⁵

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 United Energy on its meter tender and evaluation processes.⁶⁶

We also reviewed our 2012–15 AMI budget and charges determinations.⁶⁷

⁶⁴ AER, Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services, October 2015, pp. 16-35, 16-36.

⁶⁵ AER, Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services, October 2015, p. 16-40.

⁶⁶ AER Information Request #44, response from United Energy, dated 19 February 2016.

⁶⁷ 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?ff0=type%3Aaccr_aer_ami_charges&ff1=field_accr_aer_effective_date%3A2012

Forecast opex

We considered United Energy'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.⁶⁸ 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.⁶⁹

16.3.3.3 Exit fee

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

- our final decision on United Energy'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 United Energy'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 United Energy. 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.

⁶⁸ AER, *Better regulation: Expenditure forecast assessment guideline for distribution*, November 2013, p. 32.

⁶⁹ For a further discussion on the opex assessment approach, see; AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, pp. 16-36 to 16-38.

16.3.4.2 Annual metering charges

Forecast capex

Our final decision approves \$13.7 million (\$2015) in capex for United Energy's alternative control metering services. This is equal to 100 per cent of United Energy's revised capex forecast. Table 16.10 sets out our final decision on each component making up United Energy's metering capex.

Table 16.10 Final decision on United Energy's metering capex (\$2015)

| | Revised proposed | Approved |
|-------------------------------|------------------|----------|
| Remotely read interval meters | 6.0 | 6.0 |
| IT | 7.5 | 7.5 |
| Communications | 0.3 | 0.3 |
| Total | 13.7 | 13.7 |

Source: United Energy, Revised regulatory proposal 2016–20, Metering PTRM and exit fees, January 2016, 'PTRM input' tab.

Remotely read interval meters

Meter hardware unit costs

We accept United Energy's proposed meter hardware costs.

United Energy did not accept our preliminary decision on the meter hardware costs.⁷⁰

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

⁷⁰ United Energy, *Revised Regulatory Proposal*, January 2016, p. 102.

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.

United Energy and Jemena formed a partnership to undertake the AMI roll-out and contracted with Jemena Asset Management (JAM) to manage this. JAM undertook a tender process and appointed a sole provider, Secure Meters, for its AMI roll out.⁷¹

Having examined United Energy'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.⁷² Our consultants, Impaq Consulting also maintained that United Energy's vendor contracts had been let on a competitively tendered basis.⁷³

United Energy 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 United Energy 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 and volumes

We accept United Energy's revised meter installation costs and meter volumes.

We accepted United Energy proposed meter installation costs and meter volumes in our preliminary decision.⁷⁴

⁷¹ Energeia, *Review of Victorian DNSP's AMI Budget Applications*, October 2011, p. 73.

⁷² AER *Final Determination—AMI budget and charges applications 2012–15*, 31 October 2011, p. 146; <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/united-energy-ami-budget-and-charges-determination-2012-15/final-decision>

⁷³ Impaq Consulting, *Review of DNSP's AMI Budget Submissions for 2012 to 2015*, 20 July 2011, p. 150.

⁷⁴ AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-40.

United Energy has now revised these to take into account the extra five months to 1 December 2017 for the commencement of metering contestability.⁷⁵ This has led to a slight increase in volumes, which we consider reasonable.

IT/Communications

We accept United Energy's revised IT and communications costs.⁷⁶

We accepted United Energy's proposed IT and communication costs in our preliminary decision.

United Energy has accepted our preliminary decision on the IT expenditure (\$7.5 million (\$2015)) and has adjusted the communications expenditure slightly, by 0.2 million (\$2015), to account in the delay to the commencement of metering competition of five months.⁷⁷ We consider this to be a reasonable response to the delay in the commencement of metering competition.

Forecast opex

Our final decision approves \$61.9 million (\$2015) in alternative control metering opex for United Energy's 2016–20 regulatory control period. This is more than United Energy's revised forecast of \$52.9 million (\$2015).

Our final decision approves more opex than United Energy included in its alternative control metering proposal because of our approach to cost allocation (see section 16.3.1.1). Compared to United Energy'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 United Energy's opex. The corollary of this is that we have allocated less opex to United Energy's standard control network services than proposed. This leads to a lower base than United Energy proposed for standard control network services.

Base

We determined United Energy's base annual opex to be \$11.8 million (\$2015).

Table 16.11 sets out the components of our final decision regarding United Energy's base opex for the 2016–20 regulatory control period. It shows that the key difference from United Energy's revised proposal is that our final decision reallocates less of United Energy's base opex to standard control network services. By doing this, we have approved a higher base than United Energy forecast in its revised proposal. We explain our cost allocation approach between standard and alternative control metering services in section 16.3.1.1.

⁷⁵ United Energy, *Revised Regulatory Proposal*, January 2016, p. 103.

⁷⁶ AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p. 16-40.

⁷⁷ United Energy, *Revised Regulatory Proposal*, January 2016, p. 103.

Table 16.11 AER's assessment of United Energy's base (\$million, 2015)

| Cost category | Revised proposal | Final decision |
|--|------------------|----------------|
| <u>Raw base</u> | | |
| 2014 reported opex | 24.0 | 24.0 |
| <u>Non-recurrent cost</u> | | |
| Adjustment for one-off costs | (1.6) | (1.6) |
| <u>Reallocation of costs</u> | | |
| Costs moved to standard control services | (12.4) | (10.6) |
| <u>Adjusted base</u> | | |
| Base opex | 10.0 | 11.8 |

Source: AER analysis; United Energy, *Revised Regulatory Proposal 2016–2020, Metering opex - RRP* January 2016; United Energy, AER information request #054, 24 March 2016.

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

Using the revealed costs approach, we selected United Energy's actual opex in 2014 as our starting point. In 2014, United Energy's actual opex was \$24.0 million (\$2015). We selected United Energy's actual metering opex in 2014 for two reasons. First, it is the last completed year from which we have audited accounts on United Energy'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 United Energy had been set a target to have completed its rollout of AMI before the commencement of the 2014 year.⁷⁸

The next step in our assessment of United Energy's base involved considering whether we should make an adjustment for non-recurrent costs. At the preliminary decision stage, we applied the same adjustment to United Energy base for non-recurrent costs as Jemena did in its initial proposal.⁷⁹ We used Jemena as a 'comparator' because United Energy had not forecast an adjustment for non-recurrent costs. Jemena is also a similar size to United Energy in terms of customers. In response to this benchmark approach, United Energy's revised proposal applied an adjustment of \$1.6 million (\$2015) for non-recurrent costs. This amount is reflective of our preliminary decision adjustment so we have applied it in developing our forecast in this final decision.

⁷⁸ AMI Cost Recovery Order, cl. 14.1.

⁷⁹ AER, *Preliminary Decision, United Energy distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, pp. 16-43.

We consider that following the removal of non–recurrent expenditure, United Energy’s actual opex in 2014 does not contain material inefficiencies. We reached this 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.⁸⁰ We have therefore decided not to make an efficiency adjustment to the base level of opex.

The final step we took in determining United Energy's base was a cost allocation process between standard and alternative control metering services. This process is outlined in section above. After applying our approach to cost allocation, we determined United Energy's base opex to be \$11.8 million (\$2015).⁸¹

Step

Our final decision approves United Energy's proposed step change associated with the testing of new low voltage current transformer (LVCT) meters.⁸²

We will only accept a proposed step change if it is associated with a new regulatory obligation or a capex/opex trade-off.⁸³ This position is consistent with our Expenditure forecast assessment guideline.⁸⁴

In support of its proposed step change, United Energy stated that the number of tests it conducted of LVCT meters in 2014 was minimal. Approximately 90 percent of its non–AMI LVCT meter replacements were carried out in 2014 and so it ceased testing those newly installed meters in that year.⁸⁵ United Energy states that this means that its '2014 testing costs are understated and not suitable to use as the base for the period 2016 to 2020'.⁸⁶

We are satisfied that the costs involved with the testing of LVCT meters relates to a regulatory requirement that was not captured in the 2014 base year. Clause 7.6 and schedule 7.3 of the NER require LVCT meters to be tested within five years of installation. The relevant meters were installed in United Energy in the 2011–15 regulatory control period. Thus, we accept that to comply with the NER United Energy will have to test them in the 2016–20 regulatory control period.

Our final decision is to approve the proposed step change for LVCT meter testing. This is on the basis that we have determined that the associated costs relate to a new regulatory obligation.

⁸⁰ See Attachment 7 to this final decision.

⁸¹ See Table 16.11 above.

⁸² United Energy, *Revised Regulatory Proposal*, January 2016, p. 103.

⁸³ AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

⁸⁴ AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

⁸⁵ United Energy, *Revised Regulatory Proposal*, January 2016, p. 108.

⁸⁶ United Energy, *Revised Regulatory Proposal*, January 2016, p. 108.

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 and an output growth adjustment based on forecast customer numbers.

With respect to real price growth, our final decision accepts the labour to non–labour weighting (62:38) applied in United Energy's revised proposal.⁸⁷ However, we do not accept the overall escalators because this is not consistent with our final decision on United Energy's opex for standard control services.⁸⁸

In regards to output growth we accept United Energy's proposal that an adjustment should be made based on customer numbers. We further accept United Energy's proposal that no output growth would be applied after 2017. Our final decision agrees with United Energy that 'rate of change is not relevant beyond [2017] due to metering contestability'.⁸⁹ Once trended forwarded, we calculated an alternative metering opex forecast of \$61.9 million (\$2015) for the 2016–20 regulatory control period.

16.3.4.3 Metering exit fee

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

United Energy's proposed exit fee includes an administrative and capital cost component. The administrative component recovers clerical costs associated with a customer leaving United Energy'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 United Energy's service. This is derived from the opening metering asset base which we approve for United Energy in this final decision.

Our final decision accepts the administrative cost component of United Energy's proposed exit fees. But after adjusting for actual CPI, we have not accepted United Energy's proposed opening metering asset base. Our final decision accepts an opening metering asset base value as of 1 January 2016 of \$212.3 million (\$ nominal) rather than United Energy's proposed \$213.2 million (\$ nominal). As a result, we have not accepted the capital component to United Energy's exit fee proposal. This leads to lower than proposed exit fees.

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

⁸⁷ United Energy, *Revised Regulatory Proposal 2016–2020, Metering opex - RRP* January 2016

⁸⁸ AER, *Final decision, United Energy distribution determination 2016 to 2020, Attachment 7 - Operating expenditure*, May 2016.

⁸⁹ United Energy, *Revised Regulatory Proposal*, January 2016, p. 107.

administrative costs those distributors proposed in the case of removing a meter.⁹⁰ 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.

16.3.4.4 Control mechanism

United Energy's revised proposal sought amendments, or further clarification, with respect to the control mechanism that will apply to metering prices. This was in relation to adjustment T_t , metering exit fees, and the B_t true-up.

Adjustment T_t

We do not accept United Energy proposal regarding adjustment T_t .

Our final decision approves an annual metering charges revenue cap formula that includes an adjustment T_t (see section 16.3.1.3). We have defined T_t as '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'.⁹¹

In its revised proposal, United Energy submitted that the definition we have given to adjustment T_t should refer to the cost recovery order in council.⁹² We took this proposal into account but concluded that our definition of adjustment T_t is sufficiently clear and does not require any amendment. To avoid any doubt, however, we confirm that adjustment T_t in the metering charges revenue cap formula set out in section 16.3.1.3 gives effect to the transition charges provisions in clause 5L of the cost recovery order in council.

Metering exit fees

Our final decision approves a metering exit fee which is payable to United Energy when a customer leaves its regulated metering services. United Energy sought clarification about how it should treat these payments.⁹³

We confirm that the payment of an exit fee to United Energy will not be treated as revenue for the provision of metering services. As a result, we agree with how United

⁹⁰ 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.

⁹¹ See section 16.3.1.3 above.

⁹² United Energy, *Revised Regulatory Proposal*, January 2016, p. 113.

⁹³ United Energy, *Revised Regulatory Proposal*, January 2016, p. 113.

Energy's revised proposal states the capital and opex components of its exit fee should be treated. That is:⁹⁴

- the capital component of any exit fees received during the 2016–20 regulatory control period should be deducted from the MAB at the commencement of the subsequent regulatory period (1 January 2015)
- the exit fee opex component represents the increment costs of retiring meters and is not included in United Energy's revenue cap.

True-up term B_t

We do not accept United Energy's proposal regarding true-up term B_t .

United Energy's revised proposal stated that we should allow adjustments for differences between forecast and the actual number of existing metering customers that will be subject to competition (or churn) in the future.⁹⁵ It stated that this could be given effect to through the true-up term B_t in the annual metering charges revenue cap formula.⁹⁶

In our final decision we have defined the true-up term B_t as 'the sum of annual adjustment factors in year t as calculated in the unders and overs account in appendix B'.⁹⁷ In accordance with this definition, we confirm that true-up term B_t does not allow for an adjustment between forecast and the actual number of existing metering customers that churn in the 2016–20 regulatory control period.

We are required to provide United Energy with an opportunity to recover at least the efficient costs of providing direct control services.⁹⁸ Our view is that the provisions in the NER relating to pass throughs provide United Energy with that opportunity. This is because if there is a material under or over recovery in revenue due to customer churn than those provisions can be applied in such a way that United Energy's opportunity to recover at least its efficient costs will be preserved. As set out in Attachment 15, the pass through provisions of the NER will also apply to alternative control services.

⁹⁴ United Energy, *Revised Regulatory Proposal*, January 2016, p. 113.

⁹⁵ United Energy, *Revised Regulatory Proposal*, January 2016, p. 113.

⁹⁶ United Energy, *Revised Regulatory Proposal*, January 2016, p. 113.

⁹⁷ See 16.3.1.3 above.

⁹⁸ NEL, s. 7A(2).

A Ancillary network services prices

A.1 Ancillary network services

Table 16.12 Fee based ancillary network services prices for 2016, final decision (\$2016)

| Fee based service | Hours | Final decision price |
|---|----------------|----------------------|
| Field officer visits—Existing premises | | |
| Special read (basic meter) | | 21.12 |
| Special read (interval meter) | | 21.12 |
| Re-energise (fuse insert) | Business hours | 44.98 |
| De-energise (fuse removal) | Business hours | 44.98 |
| Express move in re-energise (fuse insert) | Business hours | 67.82 |
| Re-energise (fuse insert) | After hours | 79.82 |
| Express move in re-energise (fuse insert) | After hours | 125.52 |
| De-energise at point of attachment (pole/pit/premise) | Business hours | 347.69 |
| Temporary supplies (excluding inspection)—Coincident disconnection where United Energy is the responsible person | | |
| Standard single phase | Business hours | 454.27 |
| Multi phase to 100A | Business hours | 454.08 |
| Standard single phase | After hours | 693.76 |
| Multi phase to 100A | After hours | 693.58 |
| Temporary supplies (excluding inspection)—Where United Energy is not the responsible person | | |
| Single phase servicing and energisation only | Business hours | 421.56 |
| Multi phase servicing and energisation only | Business hours | 421.56 |
| Single phase servicing and energisation only | After hours | 693.76 |
| Multi phase servicing and energisation only | After hours | 693.76 |
| New connection—Where United Energy is the responsible person | | |
| Single phase single element | Business hours | 454.27 |
| Single phase two element (off peak) | Business hours | 454.27 |

| Fee based service | Hours | Final decision price |
|--|----------------|----------------------|
| Three phase direct connected | Business hours | 454.08 |
| Single phase single element | After hours | 693.76 |
| Single phase two element (off peak) | After hours | 693.76 |
| Three phase direct connected | After hours | 693.58 |
| New connections—Where United Energy is not the responsible person | | |
| Single phase single element | Business hours | 421.56 |
| Single phase two element (off peak) | Business hours | 421.56 |
| Three phase direct connected | Business hours | 421.56 |
| Single phase single element | After hours | 693.76 |
| Single phase two element (off peak) | After hours | 693.76 |
| Three phase direct connected | After hours | 693.76 |
| Service vehicle visits (without inspection) | | |
| Service truck—first 30 minutes | Business hours | 322.74 |
| Each additional 15 minutes | Business hours | 66.74 |
| Wasted service truck visit | Business hours | 279.94 |
| Service truck—2 hours minimum | After hours | 714.28 |
| Each additional 15 minutes | After hours | 92.55 |
| Wasted service truck visit | After hours | 714.28 |
| Truck visit + 1 x additional 15 minutes | Business hours | 389.48 |
| Truck visit + 2 x additional 15 minutes | Business hours | 456.22 |
| Truck visit + 3 x additional 15 minutes | Business hours | 522.95 |
| Truck visit + 4 x additional 15 minutes | Business hours | 589.69 |
| Truck visit + 5 x additional 15 minutes | Business hours | 656.42 |
| Truck visit + 6 x additional 15 minutes | Business hours | 723.15 |
| Truck visit + 1 x additional 15 minutes | After hours | 806.83 |
| Truck visit + 2 x additional 15 minutes | After hours | 899.39 |
| Truck visit + 3 x additional 15 minutes | After hours | 991.95 |
| Truck visit + 4 x additional 15 minutes | After hours | 1,084.50 |
| Truck visit + 5 x additional 15 minutes | After hours | 1,177.05 |
| Truck visit + 6 x additional 15 minutes | After hours | 1,269.61 |

| Fee based service | Hours | Final decision price |
|--------------------------------------|-------|----------------------|
| Meter equipment test | | |
| Single phase | | 251.46 |
| Single phase (each additional meter) | | 120.66 |
| Multi phase | | 251.55 |
| Multi phase (each additional meter) | | 120.66 |
| Remote AMI services | | |
| Remote meter configuration | | 59.97 |
| Remote special meter reading | | 0.81 |
| Remote re-energise | | 10.13 |
| Remote de-energise | | 10.13 |

Source: United Energy, *2016 pricing proposal*, 19 November 2016, pp. 64–66.

Table 16.13 Quoted service ancillary network services hourly labour rates for 2016, final decision (\$2016)

| Service description | Hours | Final decision hourly labour rates |
|--------------------------------------|----------------|------------------------------------|
| Field worker—one person | Business hours | 123.25 |
| Field worker—one person | After hours | 175.03 |
| Field worker—one person plus vehicle | Business hours | 144.48 |
| Field worker—one person plus vehicle | After hours | 196.27 |
| Administration | Business hours | 95.23 |
| Senior engineer | Business hours | 181.51 |
| Project planner | Business hours | 181.51 |

Source: United Energy, *2016 pricing proposal*, 19 November 2016, p. 67.

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, United Energy must maintain an annual metering charges unders and overs account in its annual pricing proposal.

United Energy 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.⁹⁹ 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.

United Energy must provide details of calculations in the format set out in Table 16.14. 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, United Energy 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.

⁹⁹ 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 16.14 Example calculation of annual metering charges unders and overs account (\$'000, nominal)

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

Notes: (a) Approved annual metering charges revenue under/over recovery for regulatory year t. This is the B_t parameter in the annual metering charges revenue cap formula.
(b) Opening balance is the previous year's closing balance.
(c) United Energy 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.