



FINAL DECISION
Energex determination 2015–16
to 2019–20

Attachment 16 – Alternative
control services

October 2015

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Note

This attachment forms part of the AER's final decision on Energex's 2015–20 distribution determination. 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 mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

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

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

16 Alternative control services

Alternative control services are services provided by distributors to specific customers. They do not form part of the distribution use of system revenue allowance provided by us to 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 determination on the prices Energex is allowed to charge customers for the provision of ancillary network services, metering, and public lighting. The approved prices are set out at appendix A.

16.1 Public Lighting

16.1.1 Final decision

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

- a nominal post-tax weighted average cost of capital (WACC) of 6.01 per cent instead of the proposed 7.42 per cent
- imputation credit assumption of 40 per cent instead of the proposed 25 per cent.

This final decision adopts the same estimate of WACC as for standard control services. The reasons for the nominal post-tax WACC and imputation credit assumption are discussed in attachment 3 — Rate of return.

In all other respects we have approved Energex's proposal. Final decision prices for each light type are set out in Table 16.1.

Table 16.1 Final decision prices for public lights, \$ day

	2015—16	2016—17	2017—18	2018—19	2019—20
Major public lights non-contributed	0.78	0.80	0.82	0.84	0.87
Major public lights contributed	0.27	0.28	0.29	0.29	0.30
Minor public lights non-contributed	0.36	0.37	0.38	0.39	0.40
Minor public lights contributed	0.13	0.13	0.14	0.14	0.15

Source: AER analysis.

Form of control

Our final decision is to apply a price cap for the form of control to public lighting, consistent with the final framework and approach (F&A). Figure 16.1 sets out the control mechanism formulas for public lighting.

Figure 16.1 Public lighting formula

$$p_t^i = p_{t-1}^i(1 + \Delta\text{CPI}_t)(1 - X_t^i) + A_t^i$$

where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹ from the December quarter in year $t-2$ to the December quarter in year $t-1$, calculated using the following method:

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

divided by

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

minus one.

For example, for the 2016–17 year, $t-2$ is the December quarter 2014 and $t-1$ is the December quarter 2015 and in the 2017–18 year, $t-2$ is the December quarter 2015 and $t-1$ is the December quarter 2016 and so on.

X_t^i is the X factor for service i in year t , as set out in Table 16.2.

Table 16.2 X Factors for annual public lighting charges (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	-0.98	-0.98	-0.98	-0.98

Source: AER analysis.

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life.

¹ 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.

16.2 Ancillary network services

Our final decision refers to the service groups identified as 'fee based services' and 'quoted services' collectively as 'ancillary network services'. This approach is consistent with our final F&A and how these services are referred to in other jurisdictions.²

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

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.⁴ 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).

16.2.1 Final decision

We accept Energex's revised proposal for ancillary network services. For these services, Energex's proposed prices do not exceed prices based on maximum labour rates (for the distributor's labour types) which we consider efficient. Our reasoning is detailed in section 16.2.4.

Our final decision price cap formulae for fee based services and quoted services are set out in Figure 16.2 and Figure 16.3 respectively. Energex's 2016–17 ancillary network service prices will be determined by the prices we approved for 2015–16 and the application of these formulae. Our final decision 2015–16 approved prices for Energex's ancillary network services prices are set out in appendix A.

² AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 45; AER, *Preliminary Decision: Energex determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–6; AER, *Final Decision: Ausgrid distribution determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–7; AER, *Final Decision: ActewAGL distribution determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–6.

³ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 45; AER, *Preliminary Decision: Energex determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–6.

⁴ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 65.

Form of control—fee based services

Our final decision applies a price cap form of control for fee based services.⁵ Under this form of control, we approved a schedule of prices for 2015–16 which are set out in Table 16.16 of appendix A. From 2016–17 and for each subsequent year of the 2015–20 regulatory control period, the year t prices are determined by adjusting the previous year's prices by the formula in Figure 16.2.

Figure 16.2 Fee based ancillary network services formula

$$p_t^i = p_{t-1}^i(1 + \Delta CPI_t)(1 - X_t^i) + A_t^i$$

where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities⁶ from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

For example, for the 2016–17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017–18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is the X factor for service i in year t as set out in Table 16.3.⁷

Table 16.3 AER final decision on X factors for each year of the 2015–20 period (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–0.41	–0.61	–0.76	–0.91

Source: AER analysis.

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

⁶ 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.

⁷ If during the 2015–20 regulatory control period Energex submits a pricing proposal which seeks an adjustment with respect to clause 11.60.4(d)(2) of the NER, then the AER can give effect to that proposal using the X factor.

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.

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life.

Form of control— quoted services

Our final decision applies a formula to determine the cost build-up of services that are priced on a 'quoted' basis.⁸ Figure 16.3 sets out the price cap formula and Table 16.17 in appendix A sets out the approved 2015–16 labour rates for quoted services.

Figure 16.3 Quoted services formula

Price = Labour + Contractor Services + Materials + Capital Allowance

where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. From 2016–17, base labour is escalated annually by $(1+\Delta CPI_t)(1-X_i)$, where:

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities⁹ from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

For example, for the 2016–17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017–18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is the X factor for service i in year t, as set out in Table 16.3.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge

⁸ AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, pp. 67–68.

⁹ 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.

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.

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

16.2.2 Energex's revised proposal

Energex's revised proposal largely accepted our preliminary decision for fee based services and quoted services.¹⁰ However, its revised proposal contained some re-scoped supply abolishment services to include an additional resource for meter removal which was erroneously omitted from its initial proposal.

The revised proposal also included a number of additional services which are permutations of services approved in our preliminary decision. Energex considered the permutations are required to rectify omissions in its initial proposal. The service permutations include different metering types, additional labour, after hours service and inclusion of traffic control.

16.2.3 Assessment approach

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

- Energex's revised regulatory proposal¹¹
- maximum total labour rates we developed for Queensland. Our findings are informed by our consultant, Marsden Jacob Associates', analysis¹²
- labour is the key input in determining an efficient level of prices for ancillary network services. Therefore, we focused on comparing Energex's proposed total labour rates against maximum total labour rates that we developed. In this final decision 'total labour rates' comprise raw labour rates, on-costs and overheads.

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

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

¹⁰ Energex, *Revised regulatory proposal*, July 2015, p. 141.

¹¹ Energex, *Revised regulatory proposal*, July 2015, p. 139–141.

¹² Marsden Jacob Associates, *Final provision of advice in relation to alternative control services—public version*, 20 October 2014.

As with our preliminary decision, we obtained maximum rates for each of these components. We applied these maximum (component) rates to derive maximum total labour rates. We consider that using our maximum labour rates to determine appropriate fees for services will provide Energex with a reasonable opportunity to recover at least the efficient costs it incurs in providing these services. It will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services. Our maximum total labour rates are set out in Table 16.4. These labour rates are consistent with those developed in our preliminary decision.

Table 16.4 Maximum allowed total labour rates

Labour category	AER maximum total labour rates (\$ per hour, \$2014–15)
Apprentices	N/A
Power workers	125.07
Administration/clerical	73.90
Customer connections labour rate	N/A
Electrical system design advisors	170.55
Technical/service persons	181.92
Para professional	181.92
Supervisors	181.92
Professional managerial	170.55
System operators	N/A
Senior professional	N/A

Source: AER analysis.

Note: Rates shown here are AER maximum total labour rates developed by the AER. Some rates cannot be shown as has Energex claimed confidentiality on its total labour rates.

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

16.2.4 Reasons for final decision

We accept Energex's revised proposal for ancillary network services. We note Energex largely accepted our preliminary decision prices for fee based services and quoted

services.¹³ Our final decision approved prices for these services are contained within Energex's 2015–16 pricing proposal which we approved in April 2015 and for transparency are set out in Table 16.16 and Table 16.17 in appendix A.

We also accept Energex's revised proposal's re-scoped supply abolishment services and additional services which are permutations of services approved in our preliminary decision. We note Energex's underlying labour rates used to derive the prices for these services do not exceed maximum labour rates which we consider efficient for providing these services. Our final decision prices for these services are also set out in Table 16.16 and Table 16.17 in appendix A.

With regard to the re-scoped supply abolishment services to include an additional labour resource for meter removal, Energex noted this was erroneously omitted from its initial proposal. It noted the additional resource was previously classified as a standard control service in the 2010–15 regulatory control period but should now form part of the supply abolishment fee based services. We agree with Energex that the meter removal labour should be included as a fee based service and form part of the supply abolishment services. We note Energex has calculated the costs for this service consistent with the approach we approved in our preliminary decision.

With regard to the additional services included in Energex's revised proposal, we accept the permutations proposed. We consider these permutations will allow Energex to establish more accurate prices which will provide clarity to customers regarding the cost of particular fee base services. For example, our preliminary decision approved a price for a customer initiated supply enhancement service for an overhead service upgrade to a multi phase meter during business hours. Energex's revised proposal included an additional service for these tasks to be undertaken after hours. We consider this is prudent approach otherwise Energex would be required to cost this service as a quoted service. We note Energex has calculated the costs for these additional services consistent with the approach we approved in our preliminary decision.

16.3 Metering

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

Currently, competition in metering is limited to large customers in the national electricity market while regulated distributors have the sole responsibility to provide small customers with metering services.¹⁴

¹³ Energex, *Revised regulatory proposal*, July 2015, p. 141.

¹⁴ NER cl. 7.2.3(a). Small customers refers to any customer with less than 160MWh annual consumption (effectively all residential and small business customers fall into this category).

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

The AEMC published its draft rule on 26 March 2015.¹⁵ It provides that the AER should determine 'the arrangements for a DNSP to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.¹⁶ Other key features of the draft rule change include:

- the transfer of the role and responsibilities of the existing 'Responsible Person' to a new type of Registered Participant called a Metering Coordinator
- allowing any person to become a Metering Coordinator, subject to meeting the registration requirements
- permitting a large customer to appoint its own Metering Coordinator
- requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.¹⁷

The AEMC's final determination is due 26 November 2015.¹⁸ In making our final decision, we have taken the AEMC's draft determination into account. In doing so we have sought to establish a regulatory framework for the 2015-20 regulatory period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 December 2017.¹⁹ This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

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

¹⁵ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015.

¹⁶ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

¹⁷ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. iii.

¹⁸ AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

¹⁹ AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

16.3.1 Final decision

16.3.1.1 Structure of metering charges

We classify type 5 and 6 metering services as alternative control services. Our final decision is that the control mechanism for alternative control metering services will be caps on the prices of individual services.

Our final decision approves two types of metering service charges:

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

Appendix B outlines in more detail how our approved structure of metering charges will work.

16.3.1.2 Annual metering services charges

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

- Opening metering asset base

We approve an opening metering asset base (MAB) value as at 1 July 2015 of \$416.0 million (\$nominal). Our final decision is based on our assessment of how Energex removed metering assets from its regulatory asset base (RAB) for standard control services.

- Depreciation

We accept the proposed remaining lives of each asset category (15 years).

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

- Rate of return

Our final decision accepts that the same weighted average cost of capital (WACC) and imputation credit (gamma) values for standard control services should apply to alternative control metering services.

See attachments 3 and 4 for our decision on WACC and gamma values, along with our reasons.

However, unlike for standard control service, we will not be annually adjusting Energex's return on debt.

- Forecast capex

We accept Energex's proposed forecast capex building block. Our final decision allows \$43.3 million in capex for annual metering charges (\$2014–15).

- Forecast opex

We accept Energex's proposed forecast opex building block. Our final decision allows \$78.6 million in opex for annual metering charges (\$2014–15).

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

16.3.1.3 Control mechanism

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

$$p_t^i = p_{t-1}^i(1 + \Delta CPI_t)(1 - X_t^i) + A_t^i$$

where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities²⁰ from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

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

divided by

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

minus one.

For example, for the 2016–17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017–18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is:

for the annual metering charge (non–capital component), the factor as set out in Table 16.5

for the annual metering charge (capital component), the factor as set out in Table 16.6

²⁰ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best estimate available of the index alternative index.

for the upfront capital charges, the factor as set out in Table 16.7.

Table 16.5 X factors for annual metering charges: non-capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	28.57	-2.00	-2.00	-2.00

Source: AER analysis.

Note 1: The X factor in 2016–17 incorporates a change in how Energex recovers its tax costs, from the non-capital to the capital component (see section 16.3.5.1).

Note 2: As outlined in section 16.3.5.2, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves \$85.6 (\$nominal) in revenue associated with the non-capital component of Energex's annual metering charges. This is less than the \$100.2 million (\$nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified a non-capital X factor in 2016–17 that gives effect to an decrease in annual metering prices when used in conjunction with the CPI-X formula. Refer to Table 16.19 in appendix A for the indicative price changes as result of the above X factors.

Table 16.6 X factors for annual metering charges: capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	0.40	-1.00	-1.00	-1.00

Source: AER analysis

Note: As outlined in section 16.3.5.2, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves \$239.1 (\$nominal) in revenue associated with the capital component of Energex's annual metering charges. This is more than the \$227.1 million (\$nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified capital X factors that give effect to an increase in annual metering prices when used in conjunction with the CPI-X formula. Refer to Table 16.19 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.7 X factors for annual metering charges: upfront capital charge (per cent)

	2016–17	2017–18	2018–19	2019–20
Single phase one element	-5.22	-0.37	-0.46	-0.55
Single phase two element	-0.88	-0.37	-0.46	-0.55
Multi-phase	0.81	-0.37	-0.46	-0.55
Current transformers	5.79	-0.37	-0.46	-0.55

Source: AER analysis.

Note: As outlined in section 16.3.5.2, the X factor has been used to "true-up" the difference between our preliminary and final decisions. The X factors in 2017–18 to 2019–20 are for labour price growth only.

A_t^f is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life. For fee based services, the value of A is zero.

Note—we have made a typographical adjustment to the formulae, such that time in each parameter is now denoted as a subscript, rather than superscript from the preliminary decision. This change has no effect on the operation of the formula, and is merely for consistency with the way we have described formulae in other determinations.

16.3.2 Energex's revised proposal

We made our preliminary decision in relation to Energex's initial alternative control metering proposal on 29 April 2015. In its revised proposal, Energex accepted some aspects of our preliminary decision, but not others.

16.3.2.1 Structure of metering charges

Energex's revised proposal accepted the general structure of metering charges in our preliminary decision.²¹ This structure comprised of:

- upfront capital charge for all new and upgraded meters installed from 1 July 2015
- annual metering charge comprising two components:
 - capital
 - non-capital
- no exit fee for when a customer 'churns' to a competitive metering service.²²

Though it accepted the general structure of metering charges in our preliminary decision, Energex stated that it has instigated a short-term transitional period.²³ It stated that this is necessary to implement the charging of all new and upgraded meters upfront.²⁴ Energex did not propose any funding to implement the transition.²⁵

16.3.2.2 Annual metering charge

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

²¹ Energex, *Revised regulatory proposal*, July 2015, p. 133.

²² AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–19; Energex, *Revised regulatory proposal*, July 2015, p.133.

²³ Energex, *Revised regulatory proposal*, July 2015, p. 133.

²⁴ Energex, *Revised regulatory proposal*, July 2015, p. 141.

²⁵ Energex, *Revised regulatory proposal*, July 2015, p. 141.

- generally accepted the pricing structure set out in our preliminary decision²⁶
- submitted a revised capex of \$43.3 million for annual metering charges, compared to the AER's preliminary decision accepting \$29.4 million (\$2014–15)²⁷
- accepted the AER's preliminary decision to approve Energex's initial opex proposal of \$78.6 million for annual metering charges (\$2014–15)²⁸
- accepted the AER's preliminary decision to approve an opening meter asset base (MAB) value of \$448.8 million²⁹

The pricing structure which Energex generally accepted involves separating out the cost recovery of its revised annual metering charges into capital and non-capital components. Our preliminary decision provided a detailed explanation of how this charging structure would operate.³⁰ For ease of reference, appendix B to this attachment provides that information once more.

To derive both the capital and non-capital components of its annual metering charges, Energex's revised proposal applied the building block approach. This approach involved forecasting the revenue requirement for each of the metering cost categories and then translating those amounts into price caps. Table 16.8 shows the forecast metering building block requirement in Energex's revised proposal. Table 16.9 shows the proposed annual charges for metering services that recover the total revised revenue.

Table 16.8 Energex's proposed metering building block requirement

(\$ million, nominal)	2015–16	2016–17	2017–18	2018–19	2019–20
Return on capital	33.3	32.5	31.6	30.7	29.6
Return of capital	19.1	20.7	22.4	24.0	25.8
Operating expenditure	16.7	16.7	17.0	17.7	17.9
Tax liability	5.8	6.1	6.3	6.6	6.9
Total unsmoothed revenue	74.9	75.9	77.4	78.9	80.2

Source: Energex, *Revised regulatory proposal*, July 2015, p. 137.

²⁶ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–19; Energex, *Revised regulatory proposal*, July 2015, p.133.

²⁷ Energex, *Revised regulatory proposal*, July 2015, p. 133.

²⁸ Energex, *Revised regulatory proposal*, July 2015, p. 136.

²⁹ Energex, *Revised regulatory proposal*, July 2015, p. 137.

³⁰ AER, *Preliminary decision: Energex determination 2015–16 to 2019–20*, April 2015, section 16.2.5.1.

Table 16.9 Energex's proposed annual metering service charges

(\$/year, nominal)		2015–16	2016–17	2017–18	2018–19	2019–20
Primary	Capital	24.48	26.96	29.69	32.70	36.01
	Non-capital	10.81	11.55	12.34	13.18	14.08
Load control	Capital	7.34	8.08	8.90	9.80	10.80
	Non-capital	3.24	3.46	3.70	3.95	4.22
Solar PV	Capital	17.14	18.88	20.79	22.89	25.21
	Non-capital	7.56	8.08	8.63	9.22	9.85

Source: Energex, *Revised regulatory proposal*, July 2015, p. 139.

16.3.2.3 Upfront capital charge

With regard to the upfront capital charge, Energex's revised proposal:

- generally accepted the pricing structure set out in our preliminary decision³¹
- submitted that Energex included errors in its calculation of its initially proposed capital charges which we incorporated in our preliminary decision³²
- stated that the errors should be corrected by resetting the values given to the 2015–16 upfront capital charges.³³

The pricing structure specified in our preliminary decision provided that the cost of all new and upgraded meters installed from 1 July 2015 will be recovered from customers upfront.³⁴ Energex accepted this aspect of our preliminary decision.³⁵ However, it stated that it has instigated a short-term transitional period to recovering the cost of new and upfront meters upfront.³⁶ Energex did not propose any funding to implement the transition.³⁷

Table 16.10 sets out Energex's revised upfront capital charges for new or upgraded installations. It also shows the corresponding charges we approved in our preliminary

³¹ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–19; Energex, *Revised regulatory proposal*, July 2015, p.133.

³² Energex, *Revised regulatory proposal*, July 2015, p.139.

³³ Energex, *Revised regulatory proposal*, July 2015, p.140.

³⁴ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–19.

³⁵ Energex, *Revised regulatory proposal*, July 2015, p.133.

³⁶ Energex, *Revised regulatory proposal*, July 2015, p. 133.

³⁷ Energex, *Revised regulatory proposal*, July 2015, p. 141.

decision.³⁸ According to Energex, its revised charges have removed the errors which we incorporated into our preliminary decision.³⁹ As outlined in section 16.3.5.4, we have accepted the cost inputs making up the revised upfront capital charges.

Table 16.10 Preliminary decision and revised upfront capital charges (\$2015–16)

Meter	Preliminary decision	Revised proposal
Direct Current		
Single Element, Single Phase	306.11	323.95
Dual Element, Single Phase	399.03	406.42
Polyphase	597.40	599.22
Current Transformer		
Polyphase	1684.77	1610.63

Source: Energex, *Revised regulatory proposal*, July 2015, p. 140; AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–113.⁴⁰

16.3.2.4 Control mechanism

Energex's revised proposal accepted the control mechanism specified in our preliminary decision.⁴¹ Energex stated that its 'revised proposal sets out price caps as per the AER's control mechanism formula'.⁴²

16.3.3 Assessment approach

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

We have followed the same assessment approach in our final decision. Since Energex generally accepted the structure of metering services specified in our preliminary decision, our assessment of the distributor's revised proposal focused on its revised costs.

³⁸ The upfront capital charges in our preliminary decision have been escalated by CPI and an X factor.

³⁹ Energex, *Revised regulatory proposal*, July 2015, p.140.

⁴⁰ The upfront capital charges in our preliminary decision have been escalated by CPI and an X factor.

⁴¹ Energex, *Revised regulatory proposal*, July 2015, p. 134.

⁴² Energex, *Revised regulatory proposal*, July 2015, p. 134.

16.3.3.1 Structure of metering charges

Energex's revised proposal generally accepted the structure of metering charges we approved in our preliminary decision.⁴³ In considering whether we should maintain this structure in our final determination, we were guided by:

- the AEMC's draft rule change on metering contestability
- the service classification and control mechanism factors in the NER⁴⁴
- SA Power Networks' revised proposal to reallocate the costs attributed to the capital and non-capital components of the annual metering charge.

In relation to the structure of metering services, the AEMC's draft rule states that the AER should determine 'the arrangements for a DNSP to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.⁴⁵ The way in which the AER achieves this outcome is not specified.

With regard to the service classification and control mechanism factors, they require us to consider whether it is more appropriate to allocate metering services costs through annual charges, upfront fees or network charges recovered from all customers. Table 16.11 sets out the factors which we have considered.

Table 16.11 Classification and control mechanism factors

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

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

⁴³ Energex, *Revised regulatory proposal*, July 2015, p. 133.

⁴⁴ NER, cl. 6.2.2(c) and cl. 6.2.5(d).

⁴⁵ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

We considered whether the recovery of Energex's tax liability should be moved from the non–capital component of the annual metering charge, to the capital component. This was put forward by SA Power Networks in its revised regulatory proposal.⁴⁶ We took the view that if we consider the reallocation to be correct, then we should apply it to Energex.

16.3.3.2 Annual metering charges

To develop its proposed price caps for annual metering services, Energex's revised proposal applied the building block approach. We considered this to be a good forecasting approach. Our assessment focused on the value of each building block in Energex's revised proposal.

Opening metering asset base

In assessing the proposed opening MAB value, we reviewed how Energex had separated its proposed opening value as at 1 July 2015 from the RAB for standard control services. This is consistent with our preliminary decision.

Depreciation

With respect to depreciation, we maintained our preliminary decision approach and considered the remaining asset lives Energex proposed and had regard to the opening of competition to metering services.

Forecast capex

Most of Energex's revised capex forecast for annual metering services comprises of the cost of replacing meters.⁴⁷ To assess this aspect of Energex's forecast capex, we applied the same approach used in our preliminary decision. This required us to consider the revised:

- 'material' and 'non–material' unit costs⁴⁸
- volume of 'reactive' and 'proactive' replacements.

Forecast opex

As no further issues have been raised, we maintain our preliminary decision which was to accept Energex's proposal on metering opex. We did no further assessment.

⁴⁶ SA Power Networks, *Revised regulatory proposal*, July 2015, p. 433.

⁴⁷ In its initial proposal Energex's forecast capex included the cost of new or upgraded connections and replacements. The revised proposal submitted by Energex, however, only proposes to recover the cost of replacements through the annual metering charge. This is consistent with our preliminary decision that the cost of new or upgraded connections should be recovered upfront from customers at the time of installation.

⁴⁸ Material costs relate to the hardware used to provide metering services. Non–material costs relate to the labour activities which Energex must perform in order to replace a meter.

16.3.3.3 Upfront charge

We accepted Energex's initially proposed upfront capital charges. Energex, however, proposed that those charges should be revised. In considering them, we assessed:

- whether Energex had demonstrated that an error had been made
- the reasonableness of the revised upfront capital charges in terms of costs
- the method by which any errors involving the initially proposed upfront charges should be corrected.

16.3.4 Interrelationships

We apply the same rate of return parameters for all direct control services (standard and alternative control services).

Our final decision on Energex's alternative control metering proposal therefore interrelates with our final decision on rate of return and imputation credits. Please refer to 3tattachments 3 and 4 for the rate of return and gamma values we accept for direct control services, along with our reasons.

16.3.5 Reason for final decision

16.3.5.1 Structure of metering charges

We maintain the same general structure of metering charges specified in our preliminary decision. We, however, have decided to reallocate certain costs between the capital and non–capital components of the annual metering charge. The general structure of metering charges we maintain from our preliminary decision consists of two types of charges:

1. upfront capital charge for all new and upgraded meters from 1 July 2015
2. annual metering charge comprising of capital and non–capital components.

This general structure was accepted by Energex in its revised proposal.⁴⁹ In a submission on our preliminary decision, Vector supported our approach too. In particular, it agreed with the removal of exit fees and the method by which we would 'allow distributors... to recover the “residual capital cost” of their efficient regulated investment'.⁵⁰ We, however, received submissions from the Queensland Farmers Federation, Origin Energy and the Energy Retailers Association of Australia (ERAA) which were not fully support of our structure of metering charges in our preliminary decision. In deciding whether we should maintain our preliminary decision, we considered those submissions.

⁴⁹ Energex, *Revised regulatory proposal*, July 2015, p. 134.

⁵⁰ Vector, *Submission on AER preliminary decisions on electricity distribution in Queensland & South Australia for 2015–16 to 2019–20*, 3 July 2015, p. 1.

The Queensland Farmers' Federation raised concerns with respect to the consultation leading up to the unbundling of meter services. We note these concerns, but given our preliminary decision and the AEMC's draft rule change, we do not consider the AER was in a position to conduct further consultation and meet its timelines under the NER. Further delays would also create further regulatory uncertainty for Energex and other stakeholders.

With respect to Origin's submission, it stated that the structure set out in our preliminary decision 'effectively imposes an exit fee to those customers who migrate to a "smart meter"'.⁵¹ It considered this to be the case because 'a customer taking a smart meter will bear the cost of legacy metering investments for the remaining life of the asset base rather than as a lump sum'.⁵²

Origin Energy is correct in submitting that when customers transition to alternative metering providers they will continue paying the capital component of their annual metering charge (see appendix B). However, Origin Energy appears to be unsupportive of this on the basis that it considers that customers should not pay any costs relating to a legacy meter after they have 'churned'. Such an approach, however, would not comply with the regulatory framework we administer as Energex must be given a reasonable opportunity to recover the costs of its past investments.⁵³ To understand why this is the case, the manner in which Energex recovers its legacy metering costs needs to be considered.

Prior to 1 July 2015 the capital costs Energex has incurred in relation to metering have been amortised. That is, the network service provider has incurred its capital cost for metering services upfront, which have then been added to an asset base and recovered gradually through annual charges over time. Origin Energy's submission appears to advocate for a charging structure whereby Energex would be required to 'write-off' unrecovered costs it has incurred upfront, whenever a customer churns. Such an arrangement is not consistent with the regulatory framework established under the National Electricity Law (NEL) and we have not considered such an approach. In particular the NEL requires us to provide Energex with a reasonable opportunity to recover at least its efficient costs.⁵⁴ This is inclusive of the capital costs Energex has incurred for metering services upfront and which it is yet to fully recover.

Additionally, Origin Energy stated, as did the ERAA, that the AER should give more consideration to the long term implications of the structure of metering charges we accept.⁵⁵ Our view is that we gave such consideration in our preliminary decision. This is seen with respect to the levying of upfront charges for new and upfront meters and the establishment of a 'two part' tariff for annual metering services.

⁵¹ Origin Energy, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 3.

⁵² Origin Energy, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 3.

⁵³ NEL, s. 7A(2).

⁵⁴ NEL, s. 7A.

⁵⁵ Origin Energy, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 3; ERAA, Submission on ART preliminary decision for Ergon Energy and Energex, 3 July 2015, p. 2.

Broadly, we consider the upfront charge for all new and upgraded meter is appropriate in the context of expanding competition in metering.⁵⁶ This is on the basis that it should help level the competitive playing field for new meters by providing transparent standalone prices for all new or upgraded meter connections. It will also shift how Energex's capital costs are recovered. This is from the annual metering services charge, where costs are spread across all customers, to an upfront payment which new entrants to the market are able to compete with in terms of price. These reasons for charging for new and upgraded connections upfront were outlined in our preliminary decision.⁵⁷ We consider them to still be applicable.

With regard to the annual metering charge, we maintain our preliminary decision accepting a two-part tariff comprising of capital and non-capital components. This structure of metering charges is more fully explained in appendix B. In summary, our reason for accepting a two-part tariff is to keep Energex financially "whole" through the transition to expanded metering contestability.

The Queensland Council of Social Services (QCOSS) stated that our preliminary decision did not take into account any capital or operating savings arising from the installation of smart meters.⁵⁸ It submitted that this may lead to customers failing to 'receive any benefit, at least for the next regulatory control period, from the savings arising to distributors from the installation of smart meters'.⁵⁹ With respect to this submission, we note that there are mechanisms in the NER to deal with distribution network businesses forecast and actual costs being materially different—such as, the pass through provisions.

In general, we are satisfied that our decision balances the interests of different stakeholders and gives effect to a regulatory regime robust enough to transition to metering contestability.

We have nonetheless determined that the recovery of Energex's tax liability should change. In our preliminary decision, we included the recovery of tax in the non-capital component of the annual metering charge. We are now of the view that tax should be recovered via the capital component. At the same time as making this final decision for Energex, we are making a similar determination for SA Power Networks (and Ergon Energy). In SA Power Networks' revised proposal, it stated that 'tax liability is interminably linked to the return on capital and relevant depreciation'⁶⁰ and so should be allocated to the capital component of the annual metering charge.

We agree with SA Power Networks' observation. Our final decision calculates the tax liability for metering services by using our post-tax revenue model (PTRM). This model

⁵⁶ AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–23.

⁵⁷ AER, *Preliminary decision: Energex determination 2015–16 to 2019–20*, April 2015, p. 16–33.

⁵⁸ QCOSS, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 28.

⁵⁹ QCOSS, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 28.

⁶⁰ SA Power Networks, *Revised regulatory proposal*, July 2015, p. 433.

in turn calculates a business' tax allowance by using the return on capital and depreciation building blocks as inputs.

Given this, we accept that there is a strong relationship between a business' tax allowance and its capital costs. Our final decision for SA Power Networks accepted the proposal that its tax liability be reallocated to the capital component of its annual metering charge. It follows that we should do the same for Energex (and Ergon Energy). When approached, Energex agreed that this was a better outcome, compared to the cost allocation in our preliminary decision.⁶¹

16.3.5.2 Control mechanism

Our reasons for approving the control mechanism specified in this final decision are outlined below, along with an explanation on how a "true-up" will operate.

Decision

Energex's revised proposal accepted the control mechanism specified in our preliminary decision.⁶² Energex stated that its 'revised proposal sets out price caps as per the AER's control mechanism formula'.⁶³ It also supported the classification of metering as alternative control services.⁶⁴

True-up

We confirm that a true-up will apply to both annual metering services and the upfront capital charge. This true-up will operate through the X factor and requires no amendment to the control mechanism formula specified in our preliminary decision, and approved in this final decision (see section 16.3.1.3). More specifically, to give effect to the difference between our preliminary and final decisions we have:

- adjusted the X factor in 2016–17
- used the remaining three years of the regulatory control period, to smooth the adjustment.

By doing this, Energex will be given an opportunity to recover its efficient alternative control metering costs.

16.3.5.3 Annual metering services

We accept Energex's revised capex forecast and maintain our preliminary decision accepting the initially proposed opex. We also accept the proposed standard asset lives (15 years) but not Energex's proposed opening MAB value.

⁶¹ Energex, *Response AER EGX 066*, 4 September 2015

⁶² Energex, *Revised regulatory proposal*, July 2015, p. 134.

⁶³ Energex, *Revised regulatory proposal*, July 2015, p. 134.

⁶⁴ Energex, *Revised regulatory proposal*, July 2015, p. 134.

Opening metering asset base

We do not accept Energex's proposed opening MAB value of \$448.8 million (\$nominal). Instead we approve an opening MAB value as at 1 July 2015 of \$416.0 million (\$nominal). This value is consistent with changes we made to the roll forward model for standard control services. For more information about those changes, see attachment 2 to this preliminary decision.

QCOSS provided us with a submission on our preliminary decision regarding Energex's opening MAB value. It observed that the opening MAB value is higher than its peers. In fact, QCOSS noted that 'Energex's MAB as set by [the AER] in the preliminary decision of \$448.8m is almost as high as the total MAB for all the NSW and SA distributors combined (\$465.9m)'.⁶⁵ It further stated that when Energex's total number of meters is divided by its opening MAB, the average meter costs works out to be \$206.⁶⁶ This is compared to an average value of \$14 per meter for Endeavour Energy.⁶⁷

With respect to the concerns raised by QCOSS, there are various reasons why the MABs of Energex and its peers can differ. In its initial proposal, Energex identified depreciation to be a possible factor. It pointed out that some of its metering assets were previously reported as low voltage overhead service line assets which attracted a lower depreciation rate.⁶⁸ We also note that the AER does not currently have powers to review past capex on meters. This means a key driver behind Energex's relatively higher opening MAB cannot be reviewed as part of our regulatory processes.

Depreciation

We maintain our preliminary decision accepting Energex's depreciation method of the MAB. This involved using the AER's post tax revenue model which contains a specific depreciation calculation method. We also confirm that forecast, as opposed to actual, depreciation will apply to the roll forward of Energex's MAB at the next regulatory control period.

With respect to asset lives, we accept Energex's proposal for meters to be depreciated over 15 years. We consider 15 years to be efficient because it coincides with the average technical life of Energex's meters. The result is that the cost recovery of the assets will match the length of their expected usefulness to customers.

Forecast capex

Our final decision is to accept Energex's revised capex forecast of \$43.3 million for annual metering services (\$2014–15). This is an increase on the \$29.4 million we

⁶⁵ QCOSS, *Response to AER decision for Queensland distributors 2015–2020*, July 2015, p. 25.

⁶⁶ QCOSS, *Response to AER decision for Queensland distributors 2015–2020*, July 2015, p. 25.

⁶⁷ QCOSS, *Response to AER decision for Queensland distributors 2015–2020*, July 2015, p. 25.

⁶⁸ Energex, *Regulatory proposal: July 2015 to June 2020, Attachment 59: MAB methodology*, October 2014, p. 4.

accepted at the preliminary decision stage⁶⁹ and about 27 percent of the \$160.1 million Energex forecast in its initial proposal.⁷⁰ Broadly, we have decided to approve the revised capex forecast because Energex has satisfactorily responded to aspects of the initial capex proposal which our preliminary decision did not accept.

Table 16.12 sets out Energex's initial and revised capex forecast along with our preliminary and final decisions. It shows that a key difference between Energex's initial and revised proposals is the latter's acceptance of our preliminary decision that the cost of new connections would not be recovered through the annual metering charge.

Table 16.12 Energex's capex proposals and AER decisions (\$million 2014–15)

	Initial proposal	Preliminary decision	Revised proposal	Final decision
New connections	101.4	0.0	0.0	0.0
Replacement	58.7	29.4	43.3	43.3
Total	160.1	29.4	43.3	43.3

Source: Energex, *Revised regulatory proposal*, July 2015, p. 134; Energex, *Regulatory proposal*, October 2014, p. 272; AER analysis.

Our assessment consisted of reviewing Energex's replacement proposal. To do this, we considered the proposed unit costs and forecast volumes of replacements. This is the same assessment approach we applied in our preliminary decision.⁷¹

Unit costs

We maintain our preliminary decision accepting Energex's non-material and material unit costs. The term "non-material" refers to the labour costs associated with installing a replaced meter. "Material" refers to the actual metering hardware.

In our preliminary decision, we found that Energex's non-material and material unit costs fit within our acceptable range and hence they were accepted.⁷² Energex's revised proposal included the same unit costs. We have therefore decided to accept them in this final decision.

For the material unit costs, we received advice from our consultant Marsden Jacob Associates. In our preliminary decision, we observed that all of Energex's material unit costs were within the market ranges in a report Marsden Jacobs provided us. This is except for the proposed unit cost for a multi-phase (DC) meter. We nonetheless

⁶⁹ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–38.

⁷⁰ Energex, *Regulatory proposal*, November 2014, p. 272

⁷¹ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–29.

⁷² AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–41.

concluded in our preliminary decision that any adjustment to Energex's forecast capex for annual metering charges would be material.⁷³ In response, Energex has revised its proposed unit cost for a multi-phase (DC) meter to an amount equal to our preliminary decision substitute. We should, however, note that the way in which Energex has built up its forecast means this revision only affects the upfront charge for new connections.

Our final decision is to approve Energex's non-material and material unit costs. They fall within the efficient ranges we developed for our assessment. Energex has also satisfactorily responded to aspects of its initial proposal which we did not accept in our final decision.

Volumes

Our final decision is to accept Energex's revised forecast of 135 000 meter replacements. This is equal to about 68 percent of the 200 000 meter replacements Energex initially proposed.⁷⁴

Both Energex's initial and revised forecasts for meter replacements were based on regulatory obligations under the NER and Australian Standard 1284.13.⁷⁵ Together these regulatory instruments create requirements on Energex to test the accuracy of its meters. More specifically, Chapter 7 of the NER establishes the maximum allowable overall error limits for a meter recording a customer's energy usage. For Type 5 meters this is an error reading of +/-1.5 percent at a full load.⁷⁶ For Type 6 meters it is +/-2.0 percent.⁷⁷ Because it would be inefficient to test every meter in service against these error reading levels, Australian Standard 1284.13 establishes a process for taking 'samples' of a broader meter 'population'. For more information about these regulatory requirements see section 16.2.5.2 of our preliminary decision.

In our preliminary decision we noted that Chapter 7 of the NER and Australian Standard 1284.13 create a rigorous regime for determining when replacement should occur. They establish a statistical method to determine if there are too many meters in a population recording energy inaccurately such that the entire population can be said to have failed and should be replaced. Energex's initial proposal did not, however, follow the processes established under Australian Standard 1284.13 and Chapter 7 of the NER. Rather than testing for whether particular makes and models exceed their acceptable quality level, Energex grouped its samples together according to age. Specifically, Energex conducted 10 000 tests to find if there are age groups of meters which do not comply with 'the **spirit** of AS 1284.13 and the overall installation error requirements according to the NER Chapter 7 (emphasis added)'.⁷⁸ We were not

⁷³ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–40.

⁷⁴ QLD Reset RIN 2015–20, October 2014; Energex, *Regulatory proposal*, Appendix 58, October 2014.

⁷⁵ Energex, *Regulatory proposal*, November 2014, p. , Energex, *Revised regulatory proposal*, July 2015, p. 140.

⁷⁶ NER, S7.2.3.1.

⁷⁷ NER, S7.2.3.1.

⁷⁸ Energex, *Regulatory proposal, Attachment 58*, October 2014, p. 2.

satisfied that this approach substantiated the initial forecast of 200 000 replacements so we substituted it with 100 155.⁷⁹

In response, Energex's revised proposal put forward a replacement forecast of 135 000 meters. This revised forecast is above the number of meters approved in our preliminary decision to comply with Chapter 7 of the NER and Australian Standard 1284.13. However, we have decided to approve it given:

- the difficulty in forecasting failure rates over multiple years
- the forecasted 135 000 meter replacements aligns with historical volumes.

The failure rate of meters against accuracy standards is difficult to forecast at the start of a regulatory control period. This is because a group of meters may be compliant with such standards at the time when a regulatory proposal is prepared, but decline in accuracy over the regulatory control period, to a point at which they are no longer compliant. We consider an approach to the assessment of a business' replacement forecasts based on previous practices to be appropriate.

In accordance with this approach, we consider a forecast that aligns with historical volumes to be reasonable. We have previously taken this approach when we have not accepted a business' forecast. In our preliminary decision for SA Power Networks' 2015–20 regulatory control period, we were not satisfied that the proposed replacements were supported by data on accuracy limits.⁸⁰ We therefore substituted the proposed forecast with an amount that was in line with SA Power Networks' historical volumes.⁸¹ We have applied the same approach to Energex.

Energex considers it appropriate to include replacement volumes for the five year period, as there is uncertainty around the timing of the introduction of metering contestability⁸². In accordance with Energex's current obligations, we have included forecast replacement for the whole period.

We approve the revised replacement forecast of 135 000 meters. Our final decision has been based on an approach that took into account the difficulty in forecasting failure rates over multiple years and the fact that the revised forecast is in line with historical volumes.

Forecast opex

As no further issues have been raised, we maintain our preliminary decision which was to accept Energex's proposal on metering opex.

⁷⁹ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–45.

⁸⁰ AER, *Preliminary decision: SA Power Network's determination 2015–16 to 2019–20*, April 2015, p. 16–38.

⁸¹ AER, *Preliminary decision: SA Power Network's determination 2015–16 to 2019–20*, April 2015, p. 16–38.

⁸² Energex, *Revised regulatory proposal*, July 2015, p. 134.

X factors

Energex's revised proposal submitted that it should have separate X factors for its capital and non-capital components of the annual metering charge.⁸³

In support of its proposal, Energex noted that the number of customers paying the capital and non-capital component of its annual metering charge will vary during the 2015–20 regulatory control period. In particular, it stated that the introduction of upfront capital charges (see section 16.3.5.4) means that there will be no new type 6 metering capital customers after 30 June 2015. By contrast, Energex considers non-capital customers will continue to grow, thus creating a discrepancy.

We accept Energex's observations regarding the effect of the upfront capital charge on the number of customers which will pay the capital component of the annual metering charge. We have therefore given effect to this outcome by specifying separate X factors for the capital and non-capital components. Refer to section 16.3.1.3 above where we set out those factors.

16.3.5.4 Upfront charges

We accept Energex's adoption of our preliminary decision that the cost of new or upgraded meters is recovered via an upfront capital charge. We also approve the upfront charges in Energex's revised proposal. They are approved in place of the charges we accepted in our preliminary decision.

Our preliminary decision was to accept Energex's initially proposed upfront meter charges. Energex nonetheless proposed to revise them. It stated that revisions to the upfront meter charges we accepted in our preliminary decision are required to address calculation errors Energex made in developing its proposal.⁸⁴ See section 16.3.2.3 for a comparison of the upfront capital charges approved in our preliminary decision, and Energex's revised charges.

To determine whether we should approve the revised charges, we considered:

- whether Energex had demonstrated that an error had been made
- the reasonableness of the revised upfront capital charges in terms of costs.

These considerations are discussed below along with Energex's proposed method for correction.

Demonstration of error

We are satisfied that Energex has demonstrated that it made errors in its calculation of the initially proposed upfront charges for new or upgraded meters.

⁸³ Energex, *Revised regulatory proposal*, July 2015, p. 140.

⁸⁴ Energex, *Revised regulatory proposal*, July 2015, p. 140.

Energex did not initially propose to recover the cost of new or upgraded installations via an upfront charge. This is our preferred approach. Before making our preliminary decision, we sent an information request to Energex notifying it of our position on how the cost of new or upgraded meter installations should be recovered.⁸⁵ We also sought input on how they should be calculated.⁸⁶ In response, Energex put forward a set of upfront charges for us to consider.⁸⁷ We assessed them against advice we received from Marsden Jacob about efficient material and non-material unit costs, as well as the consultant's advice on overhead and on-cost adjustments. Based on that assessment, we accepted Energex's initially proposed upfront capital charges for new or upgraded installations.

In its revised proposal Energex submitted to us that it made errors in responding to our information request. Those errors related to:

- the cost build-up of the upfront meter charges
- how the calculation of a capital allowance should apply.⁸⁸

Energex's submission that an error occurred in the cost build-up relates to its proposed overhead and on-cost adjustments. In Energex's information response to us, it presented its upfront capital charges in 2014–15 dollars (rather than 2015–16 dollars).⁸⁹ Consequently, the proposed charges reflected the distribution network provider's 2014–15 overhead and on-cost rates.⁹⁰ We are satisfied that this was an error included in our preliminary decision. The 2015–16 overhead and on-cost rates that should have been proposed by Energex are reasonable and we have accepted these in the final decision.

With regard to the calculation of the capital allowance, our preliminary decision was satisfied with the rate proposed by Energex.⁹¹ However, Energex's revised proposal stated that this rate was applied to its material rather than its labour costs.

The proposed capital allowance adjustment is intended to represent 'the return on and return of capital for non-system assets (vehicles, tools, etc.) used in the provision of services'.⁹² From the manner in which Energex devised its percentage adjustment for these costs, we accept that the capital allowance should be applied to the cost of labour. We therefore accept that Energex made an error in its initial proposal and have adjusted for this in our final decision.

⁸⁵ Energex, Email to the AER, 15 April 2015.

⁸⁶ Energex, Email to the AER, 15 April 2015.

⁸⁷ Energex, Email to the AER, 15 April 2015.

⁸⁸ Energex, *Revised regulatory proposal*, July 2015, p. 139.

⁸⁹ Energex, Email to the AER, 15 April 2015.

⁹⁰ Energex, *Revised regulatory proposal*, July 2015, p. 139.

⁹¹ AER, *Preliminary decision: Energex's determination 2015–16 to 2019–20*, April 2015, p. 16–51.

⁹² Energex, *Initial regulatory proposal, Attachment 54: Alternative control services price cap services*, October 2014, p. 3.

Reasonableness of costs

We are satisfied that the cost inputs Energex used are reasonable because they fall within the limits recommended by our consultant. We have determined that the revised upfront charges for new or upgraded meters should be approved.

We accepted Energex's initially proposed charges in our preliminary decision given that their inputs were within the maximum limits our consultant Marsden Jacob recommended that we should accept. To determine whether we should accept the revised upfront capital charges, we applied the same approach. The inputs we considered are:

- material inputs — the cost of the actual meter installed at a site
- material cost adjustments — for on-costs and a capital allowance
- labour cost adjustments — for on-costs and overheads.

Table 16.13 to Table 16.15 set out our assessment of these categories of inputs, which feed into the revised upfront meter charges. They show that the inputs Energex used to develop its revised charges fall within the maximum limits which Marsden Jacob advised we should accept. On that basis, our final decision is to approve each revised charge which Energex proposed.

Table 16.13 Material inputs (\$2015–16)

	Initial proposal	Revised proposal	Marsden Jacob maximum	Final decision
Single phase - one element	88.64	88.64	202.55	88.64
Single phase - two element	140.78	140.78	153.83	140.78
Multi phase (DC)	225.50	225.50	225.61	225.50
Multi phase (CT) - 2 man crew	486.09	486.09	Insufficient information	486.09

Source: Energex, *Revised regulatory proposal: Attachment 6 – Metering indicative prices*, July 2015, "Upfront charges" tab; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

Table 16.14 Material cost adjustments (\$2015–16)

	Initial proposal	Revised proposal	Marsden Jacob maximum	Final decision
<u>On-costs</u>				
<u>(\$2015–16) per meter</u>				
Single phase - one element	15.17	15.17	25.64	15.17
Single phase - two element	17.51	17.45	25.64	17.51
Multi phase (DC)	24.90	24.90	25.64	24.90
Multi phase (CT) - 2 man crew	61.49	61.49	Not assessed	61.49
<u>Capital allowance per meter</u>				
Single phase - one element	23.99	35.11	Not assessed	35.11
Single phase - two element	23.99	35.11	Not assessed	35.11
Multi phase (DC)	31.66	46.35	Not assessed	46.35
Multi phase (CT) - 2 man crew	63.32	92.70	Not assessed	92.70

Source: Energex, *Revised regulatory proposal: Attachment 6 – Metering indicative prices*, July 2015, "Upfront charges" tab; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, p. 33.

Table 16.15 Labour cost adjustments (percentage)

	Initial proposal	Revised proposal	Marsden Jacob maximum	Final decision
<u>On-costs</u>				
Fleet on-costs	12.60	11.2	Not assessed	11.2
<u>Overheads</u>				
General overhead	44.10	43.31	-	43.31
Corporate support overhead	Not proposed	7.57	-	7.57
Total (overheads)	44.10	50.88	59.0	50.88

Source: Energex, *Revised regulatory proposal: Attachment 6 – Metering indicative prices*, July 2015, "Upfront charges" tab; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, p. 33.

Correction method

Our final decision does not approve Energex's proposed correction method.

Energex's revised proposal submitted that to correct the errors, we should reset the approved 2015–16 upfront meter charges.⁹³ This would reset the "base" by which the price caps will be calculated in the 2015–16 regulatory control period. In that way, the errors would be removed when Energex submits its 2016–17 pricing proposal for approval and every subsequent year.

Instead of accepting this proposal, we will be applying a "true-up" using the X factors for the upfront capital charge. This approach is consistent with our control mechanism which specifies that 'a schedule of prices is **set** for the first year (2015–16)' (emphasis added). The way in which the true-up will operate is explained in more detail in section 16.3.5.2.

⁹³ Energex, *Revised regulatory proposal*, July 2015, p. 140.

A Approved prices for ancillary network services

A.1 Ancillary network services

Table 16.16 Fee based ancillary network services prices for 2015–16, final decision (\$2015–16)

Service	AER final decision
PRE-CONNECTION SERVICES (CONNECTION APPLICATION SERVICES)	
<i>Negotiation services involved in negotiating a connection agreement – simple</i>	
Standard jobs for small customer connections and real estate developments (sub-divisions). Please note that if service is non-standard, a quoted price may apply.	1,516.62
<i>Protection and power quality assessment prior to connection - simple</i>	
Solar PV 30-150 kW	3,791.55
<i>Application assessment, design review and audit real estate (sub-division) connection services - resubmission</i>	
Design assessment and preparation of offer - Resubmission	162.44
PRE-CONNECTION SERVICES (CONSULTATION SERVICES)	
<i>Site inspection in order to determine nature of connection</i>	
Small or large customer connection	324.88
<i>Provision of site-specific connection information and advice for small or large customer connections.</i>	
Protection devices and settings, fault level, network information	649.77
CONNECTION SERVICES	
<i>Customer request a temporary connection for short term supply (includes metered and unmetered) – simple</i>	

Service	AER final decision
Customer requested temporary connection (short term) and recovery of the temporary builders supply (business hours) - no CT.	1,566.41
Customer requested temporary connection (short term) and recovery of the temporary builders supply (business hours) - CT metering. Includes additional crew.	2,668.84
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - no CT.	2,200.40
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - no CT. Work requires traffic control due to imposed rules from external authorities.	3,259.28
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - CT metering. Includes additional crew.	3,773.63
Customer requested temporary connection (short term) and recovery of the temporary builders supply (after hours) - CT metering. Work requires traffic control due to imposed rules from external authorities and additional crew.	4,832.51
Customer requested temporary connection (short term) and recovery of the temporary builders supply (any time) - no CT.	2,200.40
Customer requested temporary connection (short term) and recovery of the temporary builders supply (any time) - no CT. Work requires traffic control due to imposed rules from external authorities.	3,259.28
Customer requested temporary connection (short term) and recovery of the temporary builders supply (any time) - CT metering. Includes additional crew.	3,773.63
Customer requested temporary connection (short term) and recovery of the temporary builders supply (any time) - CT metering. Work requires traffic control due to imposed rules from external authorities and additional crew.	4,832.51

Service	AER final decision
Temporary connection of unmetered equipment to an existing LV supply ² .	259.06
POST-CONNECTION SERVICES	
<i>Supply abolishment – simple</i>	
Request to de-energise an unmetered supply point.	397.77
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes (business hours).	637.14
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes (business hours). Work requires traffic control due to imposed rules from external authorities.	1,696.02
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes (after hours).	786.61
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes (after hours). Work requires traffic control due to imposed rules from external authorities.	1,845.49
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes (any time).	786.61
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for single dwellings and the community / unit one of multi-unit residential complexes (any time). Work requires traffic control due to imposed rules from external authorities.	1,845.49

Service	AER final decision
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community / unit one (business hours).	120.04
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community / unit one (after hours).	171.36
Retailer requests the service provider to abolish supply at a specific connection point (simple). To be used for multi-unit residential complexes for all units after the community / unit one (anytime).	171.36
<i>Rearrange connection assets at customers request - simple (upgrade from overhead to underground where main connection point is in existence)</i>	
Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (business hours).	242.54
Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (after hours).	346.11
Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service (any time).	346.11
<i>Overhead service line replacement at customers request (no material change to load)</i>	
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (business hours).	615.66
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (after hours).	798.67

Service	AER final decision
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (business hours). Work requires traffic control due to imposed rules from external authorities.	1,674.54
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (after hours). Work requires traffic control due to imposed rules from external authorities.	1,857.55
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (any time).	798.67
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Single phase (any time). Work requires traffic control due to imposed rules from external authorities.	1,857.55
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (business hours).	864.57
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (business hours) CT metering	864.57
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (business hours). Work requires traffic control due to imposed rules from external authorities.	1,923.45
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (after hours).	1,095.62
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (after hours). CT Metering	1,095.62

Service	AER final decision
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (after hours). Work requires traffic control due to imposed rules from external authorities.	2,154.50
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (after hours). Work requires traffic control due to imposed rules from external authorities. CT metering.	2,154.50
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (any time).	1,095.62
Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. Multi-phase (any time). Work requires traffic control due to imposed rules from external authorities.	2,154.50
<i>Auditing services – auditing/re-inspection of connection assets after energisation to network - simple</i>	
Auditing / re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 0-6.	445.41
Auditing / re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 7-30.	712.66
Auditing / re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 31-60.	852.65

Service	AER final decision
Auditing / re-inspection of connection assets after energisation - real estate development (sub-division). Number of new, modified or recovered sites (i.e. stations numbers excluding street light pits and conduits): 61+.	950.21
<i>Temporary disconnections and reconnections (which may involve a line drop) - low voltage</i>	
Temporary LV service Disconnection/reconnection - no dismantling (business hours).	347.88
Temporary LV service Disconnection/reconnection - physical dismantling (business hours).	568.37
Temporary LV service Disconnection/reconnection - no dismantling (after hours).	496.44
Temporary LV service Disconnection/reconnection - physical dismantling (after hours).	811.09
Temporary LV service Disconnection/reconnection - no dismantling (anytime).	496.44
Temporary LV service Disconnection/reconnection - physical dismantling (anytime).	811.09
<i>Customer initiated supply enhancement</i>	
Overhead service upgrade to multi-phase.	1,145.40
Overhead service upgrade to multi-phase (includes traffic control).	2,204.28
Underground service - upgrade to multi-phase.	3,051.20
Overhead service upgrade to single-phase (business hours)	1,016.34
Overhead service upgrade to single-phase (business hours). Work requires traffic control due to imposed rules from external authorities.	2,075.22
Overhead service upgrade to single-phase (after hours)	1,321.83
Overhead service upgrade to single-phase (after hours). Work requires traffic control due to imposed rules from external authorities.	2,380.71
Overhead service upgrade to multi-phase (business hours).	1,145.40
Overhead service upgrade to multi-phase (after hours)	1,537.72
Overhead service upgrade to multi-phase (business hours). Work requires traffic control due to imposed rules from external authorities.	2,204.28

Service	AER final decision
Overhead service upgrade to multi-phase (after hours). Work requires traffic control due to imposed rules from external authorities.	2,596.60
Overhead service upgrade to multi-phase (business hours) CT Metering	1,145.40
Overhead service upgrade to multi-phase (after hours) CT Metering	1,537.72
Overhead service upgrade to multi-phase (business hours). Work requires traffic control due to imposed rules from external authorities. CT Metering	2,204.28
Overhead service upgrade to multi-phase (after hours). Work requires traffic control due to imposed rules from external authorities. CT Metering	2,596.60
Underground service – upgrade to single phase (business hours)	357.68
Underground service – upgrade to single phase (after hours)	510.43
Underground service - upgrade to multi-phase (business hours)	357.68
Underground service - upgrade to multi-phase (after hours)	510.43
Underground service - upgrade to multi-phase (business hours) CT Metering	715.36
Underground service - upgrade to multi-phase (after hours) CT Metering	1,020.85
Customer consultation or appointment	
A visit to the customer's premises to advise on electrical supply matters.	220.49
De-energisation	
Retailer requests de-energisation of the customer's premises where the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - no CT.	61.40
Retailer requests de-energisation of the customer's premises where the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - CT metering.	301.64
Retailer requests de-energisation of the customer's premises where the customer has not paid their electricity account and the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - no CT.	61.40

Service	AER final decision
Retailer requests de-energisation of the customer's premises where the customer has not paid their electricity account and the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) - CT metering.	305.86
Retailer requests de-energisation of the customer's premises carried out by way of main switch seal (non-payment).	20.12
Retailer requests a de-energisation of the customer's premises and it is carried out by way of Main Switch Seal.	20.12
Re-energisation	
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (business hours).	46.90
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT metering (business hours).	46.90
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (after hours).	66.51
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT metering (after hours).	66.51
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, no CT (any time).	66.51
Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required, CT metering (any time).	66.51
Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required) (business hours).	11.32
Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required) (after hours).	75.67
Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required) (any time).	68.56
Retailer requests re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (business hours).	46.42
Retailer requests re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (after hours).	75.67
Retailer requests re-energisation for the customer's premises following a main switch seal due to non-payment of their electricity account (no visual required) (any time).	68.56
Retailer requests that fieldwork be undertaken to obtain a new reading rather than using a deemed meter reading. May also be used for retrospective move-in requests.	9.57

Service	AER final decision
Retrospective move in read required.	9.57
Retailer requests a visual examination upon re-energisation of the customer's premises - no CT (business hours).	107.76
Retailer requests a visual examination upon re-energisation of the customer's premises - CT metering (business hours).	276.34
Retailer requests a visual examination upon re-energisation of the customer's premises - no CT (after hours).	153.56
Retailer requests a visual examination upon re-energisation of the customer's premises - CT metering (after hours).	381.90
Retailer requests a visual examination upon re-energisation of the customer's premises - no CT (anytime).	153.20
Retailer requests a visual examination upon re-energisation of the customer's premises - CT metering (anytime).	417.46
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - no CT (business hours).	107.76
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - no CT (after hours).	153.56
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - CT metering (after hours).	381.90
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - CT metering (business hours).	276.34
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - no CT (anytime).	153.20
Retailer requests a visual examination upon re-energisation of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days - CT metering (anytime).	417.46
<i>Attending loss of supply (customer at fault)</i>	
Energex attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) business hours.	220.49
Energex attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) anytime.	314.65
Energex attending LV customers trouble call and found fault in LV customers installation (includes tripped safety switch, internal fault, customers overload) after hours.	314.65
ACCREDITATION / CERTIFICATION	
<i>Accreditation of design consultants</i>	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC	10,259.61

Service	AER final decision
and distribution works that are reticulated with Energex network (design accreditation). New applicant has ISO9001 accreditation with no other Energex accreditations in place.	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation). New applicant is not ISO9001 accredited with no other Energex accreditations in place.	11,956.42
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation). Applicant currently holds accreditation to undertake design services for rate 2 public lighting (design accreditation). Applicant requesting additional Energex accreditations with or without ISO9001 accreditation (priced per additional accreditation).	7,010.77
Onsite management system evaluation (irrespective of prior accreditations). Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design accreditation).	678.72
Capability evaluation (irrespective of prior accreditations). Applicant requests to obtain Energex accreditation to provide design services for real estate development (sub-division), rate 2 public lighting, LCC and distribution works that are reticulated with Energex network (design Accreditation).	649.77
Accreditation of alternative service providers (construction accreditation)	
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation). New applicant has ISO9001/AS4801/ISO14001 accreditation with no other Energex accreditations in place.	5,003.36
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation). New applicant is not ISO9001/AS4801/ISO14001 accredited with no other Energex accreditations in place.	9,386.56
Desktop management system evaluation - Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation). Applicant requesting additional Energex accreditations with or without ISO9001/AS4801/ISO14001 accreditation (price per additional accreditation).	5,003.56
Onsite management system evaluation (irrespective of prior accreditations). Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	1,357.45
Capability evaluation irrespective of prior accreditations). Applicant requests to obtain Energex accreditation to provide construction services for real estate development (sub-division) works that are reticulated with Energex network (construction accreditation).	1,328.49
Management system re-evaluation	
QA process: This is conducted on request from existing service providers and design consultants with the intent to improve their management system score.	6,787.23
Shared assets authority	

Service	AER final decision
High Level quality assessment (QA) and capability process: this is conducted to ensure the applicant has adequate safety and QA documentation to meet legislative and Energex WCS requirements. Also involves a capability assessment of the applicant's ability to conduct the work.	5,090.43
OTHER RECOVERABLE WORKS	
Customer requested appointments	
Customer requested appointments.	220.49
ATTENDANCE AT CUSTOMER PREMISES TO PERFORM A STATUTORY RIGHT WHERE ACCESS IS PREVENTED	
Energex attends a site at the customer's request and is unable to perform job due to customer's fault1 (business hours).	88.20
Energex (2 crew) attends a site at the customer's request and is unable to perform job due to customers fault (business hours).	176.39
Energex attends a site at the customer's request and is unable to perform job due to customer's fault1 (after hours).	125.86
Energex (2 crew) attends a site at the customer's request and is unable to perform job due to customers fault (after hours).	251.72
Energex attends a site at the customer's request and is unable to perform job due to customer's fault1 (anytime).	125.86
Energex (non-technical) attends a site at the customer's request and is unable to perform job due to customer's fault1 (business hours).	10.52
Energex (non-technical) attends a site at the customer's request and is unable to perform job due to customer's fault1 (after hours).	75.38
Energex (non-technical) attends a site at the customer's request and is unable to perform job due to customer's fault1 (anytime).	75.38
METER INSTALLATION	
Upfront capital charge	
Meter – DC 1 Element Single Phase	306.11
Meter – DC 2 Element Single Phase	399.03
Meter – DC Polyphase	597.40
Meter – CT Polyphase	1,684.77
After hours provision of services (incremental costs only- base cost included in metering service charge)	
After hours exchange of meter – CT metering (after hours - incremental costs only - base cost included in MSC)	344.52
After hours exchange of meter – no CT (after hours - incremental costs only - base cost included in MSC)	72.42

Service	AER final decision
After hours exchange of meter – no CT (after hours - incremental costs only - base cost included in MSC)	51.30
After hours installation of additional metering - CT metering (after hours - incremental costs only - base cost included in MSC)	344.52
After hours installation of additional metering - PV CT metering (after hours - incremental costs only - base cost included in MSC)	183.27
After hours installation of additional metering - single phase metering (after hours - incremental costs only - base cost included in MSC)	72.42
After hours installation of additional metering – multi-phase metering (after hours - incremental costs only - base cost included in MSC)	117.27
After hours installation of additional metering - PV single phase metering (after hours - incremental costs only - base cost included in MSC)	61.53
After hours installation of additional metering - PV multiphase metering (after hours - incremental costs only - base cost included in MSC)	76.34
After hours removal of meter/s from customer's premises	
After hours removal of meter - no CT (after hours - incremental costs only - base cost included in MSC)	52.05
After hours removal of meter - CT metering (after hours - incremental costs only - base cost included in MSC)	166.00
After hours provision of initial meter installation	
After hours provision of initial meter installation - CT metering - overhead connection	330.97
After hours provision of initial meter installation - CT metering - p/pole connection	378.61
After hours provision of initial meter installation - CT metering - underground connection	318.33
After hours provision of initial meter installation - single phase metering - overhead fox connection	131.67
After hours provision of initial meter installation - single phase metering - overhead connection	99.17
After hours provision of initial meter installation - single phase metering - underground connection	75.37
After hours provision of initial meter installation - multi-phase metering - overhead fox connection	166.61
After hours provision of initial meter installation - multi-phase metering - overhead connection	125.38
After hours provision of initial meter installation – multi-phase metering - underground connection	97.79
Customer requested meter test (physically test meter)	
Testing for type 5 & 6 meters - customer requested meter accuracy testing - no CT	365.40
Testing for type 5 & 6 meters - customer requested meter accuracy testing - CT metering	761.91
Customer requested meter test (physically test meter)	
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - no CT (business hours)	89.74

Service	AER final decision
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT metering (business hours)	333.57
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - no CT (after hours)	161.91
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - no CT (anytime)	161.91
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT metering (after hours)	476.02
Inspection required to check reported or suspected fault and no fault in meter is found. (no physical meter test) - CT metering (anytime)	476.02
Customer requested reconfiguration of meters	
A request to make a change from one tariff to another tariff (controlled load) - no CT	91.53
A request to make a change from residential flat (NTC 8400) to residential ToU (NTC 8900) - no CT	139.64
A request to make a change from one tariff to another tariff (controlled load) - CT metering	421.38
A request to make a change from residential flat (NTC 8400) to residential ToU (NTC 8900) - CT metering	465.47
A request to make a change from one tariff to another tariff - no CT (business hours)	91.53
A request to make a change from residential ToU (NTC 8900) to residential flat (NTC 8400)	91.53
A request to make a change from one tariff to another tariff - CT metering (business hours)	421.38
Change timeswitch - no CT	122.49
Change timeswitch - CT metering.	387.08
A request to make a change from one tariff to another tariff - no CT (after hours)	108.18
A request to make a change from one tariff to another tariff - CT metering (after hours)	601.32
A request to make a change from one tariff to another tariff - no CT (anytime)	108.18
A request to make a change from one tariff to another tariff - CT metering (anytime)	601.32
Meter alteration – meter integrity verification	
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (business hours)	128.00
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT metering (business hours)	793.15
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (after hours)	183.04
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT metering (after hours)	1,131.87
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - no CT (anytime)	183.04

Service	AER final decision
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment - CT metering (anytime)	1,131.87
METER READING	
Check read	
Customer requests a check read on the meter due to reported error in the meter reading. This is only used to check the accuracy of the meter reading.	7.64
Final read	
Retailer requires a reading for preparing a final bill for customer.	7.64
Transfer read	
Customer requests a transfer read, as a result of transferring to a different retailer during a billing period.	7.64
Estimated read	
Estimated read	7.72
METER DATA SERVICES	
Type 5-7 non-standard metering services	
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (business hours) First unit	127.90
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (business hours) Additional units	64.20
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (after hours) First unit	365.02
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (after hours) Additional units	183.23
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (anytime) First unit	365.02
A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware (anytime) Additional units	183.23
OTHER METERING SERVICES	
Instrument transformers	

Service	AER final decision
Provision, installation, testing and maintenance of instrument transformers for metering purposes	949.66
Testing and maintenance of instrument transformers for metering purposes	173.94

Source: AER analysis.

Note: For the remainder of the 2015–20 regulatory control period, Energex is required to present in its annual pricing proposal the timing of when ancillary network service prices for ‘business hours’, ‘after hours’ and ‘any time’ apply. We consider this presentation is needed for greater transparency to enable regulators, retailers, policy makers and end users to see the varied pricing impacts due to the timing of when an ancillary network service is performed.

Table 16.17 Quoted service ancillary network services hourly labour rates for 2015–16, final decision (\$2015–16)

Labour category	AER maximum total labour rates (\$ per hour, \$2015–16)
Apprentices	N/A
Power workers	Confidential
Administration/clerical	Confidential
Customer connections labour rate	N/A
Electrical system design advisors	Confidential
Technical/service persons	Confidential
Para professional	Confidential
Supervisors	Confidential
Professional managerial	Confidential
System operators	N/A
Senior professional	N/A

Source: AER analysis.

Table 16.18 Quoted ancillary network services prices for 2015–16, final decision.

Service category	Service description
Application services to assess connection application and making of compliant connection offer	Large customer connections
Undertaking design for small customer or real estate development (sub-division) connection offer (excludes detailed design undertaken after a connection offer has been accepted)	Real estate development (sub-division)
Carrying out planning studies and analysis relating to distribution connection applications (including sub-transmission and dual function assets)	Large generators or loads that require feeders that may trigger transmission or distribution works
Feasibility and concept scoping, including planning and design, for large customer connections.	Large Customer Connections
Negotiation services involved in negotiating a connection agreement - complex	Large Customer Connections
Protection and power quality assessment prior to connection - complex	Solar PV 150kW+ and non solar PV 30kW+
Application assessment, design review and audit real estate development (sub-division) connection services.	Design assessment and preparation of offer number of new, modified or recovered sites 7-30 sites
Preparation of preliminary designs and planning reports for small or large customer connection, including project scope and estimates	Large customer connection - planning report/feasibility report - additional information provided by the asset management above and beyond NSC providing general connection enquiry services prior to the submission of an application for connection (requires engagement of asset management staff outside of the NSC)
Design & construct of connection assets for large customers.	Install new ground transformer substation to service commercial load. Substation includes installation of 2 x 1500KVA TX, safelink RMU, LB Board 300m of 11kv cable
Commissioning and energisation of large customer connection assets to allow conveyance of electricity.	Large customer connections

Service category	Service description
Commissioning and energisation of connection assets for real estate development (sub-division)	Undertake high voltage switching to allow developer to connect network they have constructed as part of the real estate development (sub-division), to the existing Energex network. Energex would enter the HV switching sheet into our system and arrange for resources to undertake the forward and reverse switching with the use of existing isolation switches in the network.
Augmenting the network to remove a constraint faced by an embedded generator	Removal of network constraint for a non-registered embedded generator - UPGRADE PMT TX 315 3 PH TO 500 3 PH SQ
Review, inspection and auditing of design and works carried out by an alternative service provider prior to energisation.	Large customer connections - design
Customer requests a temporary connection for short term supply (includes metered and unmetered) - complex	Provide temporary supply of 900 amps by extending 11kv network and installing 1000KVA padmount transformer
Supply abolishment - complex	To abolish LV supply that is fed directly from UG network to primary fuses on a commercial property.
Rearrange connection assets at customers request - complex	Pole-to-pillar (installed by Energex)
Rearrange connection assets at customers request - complex	Overhead to underground where existing main connection point does not exist i.e. have to install pillar. Includes cost of connection once pillar is installed
Auditing services – auditing/re-inspection of connection assets after energisation to network - complex	Auditing / re-inspection of connection assets after energisation - large customer connections
Protection and power quality assessment	Embedded generation connected to network
Customer requested works to allow customer or contractor to work close.	Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.
Temporary disconnections and reconnections (which may involve a line drop) - high voltage	HV - switching sheets for isolation

Service category	Service description
Provision of connection services above minimum requirements.	Customer requests increase in reliability or quality of supply beyond the standard, and/or above minimum regulatory requirements (e.g. reserve feeder). (1km of 11kV Feeder 240mm ² UG, and new conduits.)
Rectification of illegal connections: work undertaken as a consequence of illegal connections resulting in damage to the network	Rectification of illegal connections or damage to overhead or underground service cables
Close out re-evaluation	QA and capability process: this is to ensure the applicant has adequate QA documentation in place to satisfy Energex QA advisor. Applicant will also be required to undertake a capability assessment to assess whether or not they meet Energex requirements.
Certification of non-approved materials to be used on the network	Certification of non-approved materials to be used on the network - simple
Certification of non-approved materials to be used on the network	Certification of non-approved materials to be used on the network - complex
Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee.	Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee.
Retailer of Last Resort (ROLR) event	<p>Preparing lists of affected sites, and reconciling data with Australian Energy Market Operator listings; handling in-flight transfers; identifying open service orders raised by the failed retailer and determining actions to be taken in relation to those service orders; arranging estimate reads for the date of the ROLR event and providing data for final NUOS bills in relation to affected customers; preparing final invoices for NUOS and miscellaneous charges for affected customers; preparing final debt statements; extracting customer data, providing it to the ROLR and handling subsequent enquiries; handling adjustments that arise from the use of estimate reads; assisting the retailer with the provision of network tariffs to be applied and the customer move in process; administration of any 'ROLR cost recovery scheme distributor payment determination'.</p> <p>This is an example cost of the insolvency of a retailer that of a size smaller than the big 3 (AGL)</p>
Customer requests the provision of electricity network data requiring customised investigation analysis or technical input	E.g. Provision of accumulation data where available on request from retailer

Service category	Service description
Customer requests the provision of electricity network data requiring customised investigation analysis or technical input	E.g. Specific request for the provision of zone substation data (F&A P78 V13) The following are the basic requirements for delivery for the half hour data requests. Task frequency days staff Initial extraction via script once 5 para professional Annual update via script once per year 2 para professional Burn to discs as required 2 para professional
Bundling (conversion) of cables carried out at the request of another party.	E.g. 1x40m span of open wire LV only replaced with LV bundled conductor. No pole replacement required.
Provision of services to extend / augment the network, to make supply available for the connection of approved unmetered equipment, e.g. public telephones, streetlights, extension to the network to provide a point of supply for a billboard & city cycle.	E.g. Installation of a x street pole to supply connection for R3 streetlighting to Railway crossing
Rearrangement of network assets	E.g. Relocate LV inline pole with pin construction & concrete collar foundation
Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.	E.g. aerial markers - install & recover marker flags - 70 marker flags for 1 month
Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.	E.g. Tiger Tails
Assessment of parallel generator applications	Assessment of parallel generator applications
Witness testing	Witness testing
Overhead service connection - non standard installation	Flying fox (catenary) overhead connection difference between the cost of a standard overhead service and the cost of a flying fox service.
Overhead service connection - non standard installation	Flying fox (catenary) overhead connection existing connection
Type 5-7 non standard metering data services	Provision of load profile data where available – Retailer requested
Type 5-7 non standard metering data services	Provision of metering data above minimum regulatory requirements.

Service category	Service description
Type 5-7 non standard metering data services	Collection, processing and transfer of higher standard energy data for customers than would otherwise be provided – Retailer requested.
Metering Load Control	Install metering related load control
Metering Load Control	Remove local control relay or time clock
Metering Load Control	Change load control relay channel at retailer, customer or other third party request, that is not a part of initial load control installation, nor part of standard asset maintenance or replacement

Source: AER analysis.

A.2 Metering

Table 16.19 Annual metering charges (\$nominal)

Annual charges (\$ nominal)		2015–16	2016–17	2017–18	2018–19	2019–20
Primary	Non–capital	10.81	7.91	8.27	8.65	9.04
	Capital	24.48	24.99	25.87	26.79	27.73
Load control	Non–capital	3.24	2.37	2.48	2.59	2.71
	Capital	7.34	7.50	7.76	8.04	8.32
Solar PV	Non–capital	7.56	5.54	5.79	6.05	6.33
	Capital	17.14	17.50	18.11	18.75	19.41

Source: AER analysis.

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

Table 16.20 AER final decision on X factors for annual metering charges: non-capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	28.57	-2.00	-2.00	-2.00

Source: AER analysis

Note 1: The X factor in 2016–17 incorporates a change in how Energex recovers its tax costs, from the non-capital to the capital component (see section 16.3.5.1).

Note 2: As outlined in section 16.3.5.2, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves \$85.6 (\$nominal) in revenue associated with the non-capital component of Energex's annual metering charges. This is less than the \$100.2 million (\$nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified a non-capital X factor in 2016–17 that gives effect to an increase in annual metering prices when used in conjunction with the CPI-X formula. Refer to Table 16.19 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.21 AER final decision on X factors for annual metering charges: capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	0.40	-1.00	-1.00	-1.00

Source: AER analysis

Note: As outlined in section 16.3.5.2, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves \$239.1 (\$nominal) in revenue associated with the capital component of Energex's annual metering charges. This is more than the \$227.1 million (\$nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified capital X factors that give effect to an increase in annual metering prices when used in conjunction with the CPI-X formula. Refer to Table 16.19 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.22 Approved upfront capital charges (\$2015–16)

Meter	(\$2015–16)
DC 1 Element Single Phase	306.11
DC 2 Element Single Phase	399.03
DC Polyphase	597.40
CT Polyphase	1684.77

Source: AER analysis; Energex, *Approved pricing proposal for 2015–16*, 12 June 2015, p. 96.

Table 16.23 AER final decision on X factors for annual metering charges: upfront capital charge (per cent)

	2016–17	2017–18	2018–19	2019–20
Single phase one element	-5.22	-0.37	-0.46	-0.55
Single phase two element	-0.88	-0.37	-0.46	-0.55
Multi-phase	0.81	-0.37	-0.46	-0.55
Current transformers	5.79	-0.37	-0.46	-0.55

Source: AER analysis

Note: As outlined in section 16.3.5.2, the X factor has been used to "true-up" the difference between our preliminary and final decisions. The X factors in 2017–18 to 2019–20 are for labour price growth only.

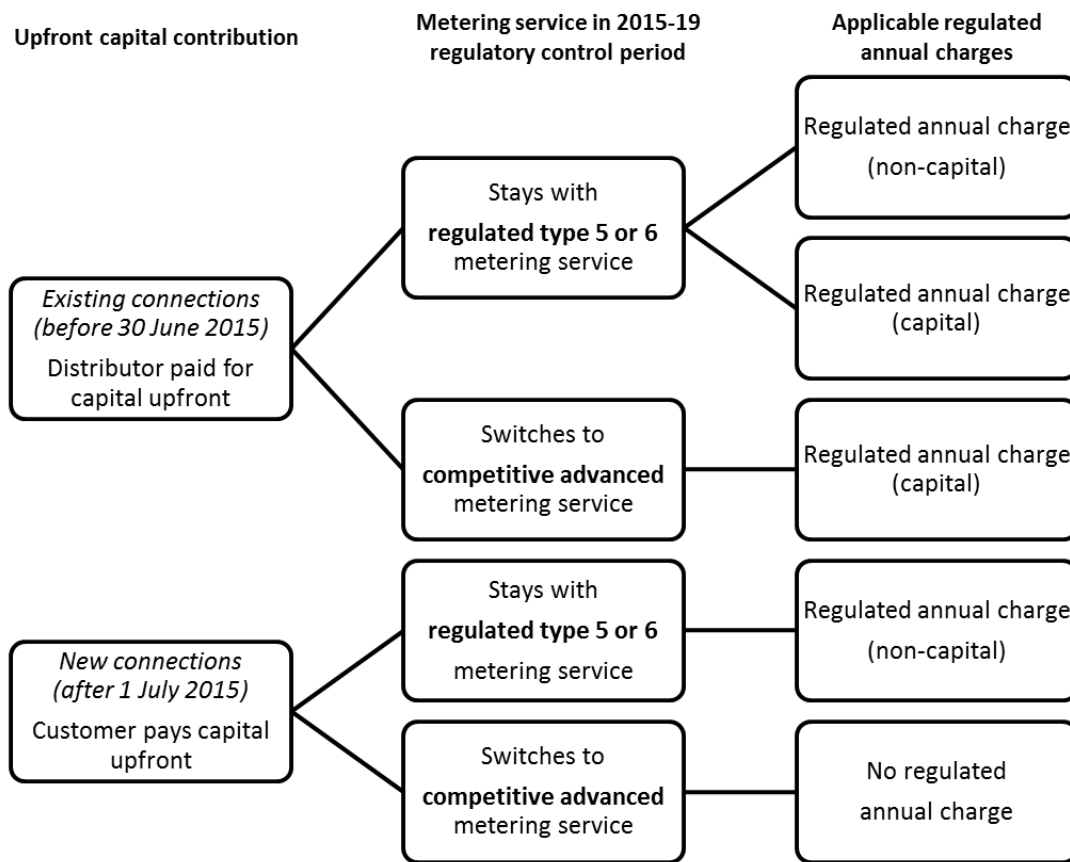
B Annual metering charge

We maintain our preliminary decision approving two types of charges:

1. upfront capital charge for all new and upgraded meters from 1 July 2015
2. annual metering charge comprising of capital and non-capital components

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

Figure 16.4 – Preliminary decision – applicable regulated annual charges



Source: AER analysis.

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

Existing connections (before 30 June 2015)

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

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

- Capital (MAB recovery⁹⁴) component of regulated annual metering charge
- Non-capital (opex) component of the regulated annual metering charge.

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

- Capital component of the regulated annual metering charge.

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

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

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

New connections (after 1 July 2015)

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

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

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

⁹⁴ The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–20 regulatory control period to include forecast replacement capex. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

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

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