



**PRELIMINARY DECISION
SA Power Networks
determination 2015–16 to
2019–20**

**Attachment 16 – Alternative
control services**

April 2015

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Note

This attachment forms part of the AER's preliminary decision on SA Power Networks' 2015–20 distribution determination. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

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

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

16 Alternative control services

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

This section describes the AER's determination on the charges that distributors can levy customers for the provision of alternative control metering services.

16.1 Metering

Our preliminary decision on SA Power Networks' 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 preliminary decision, but have had regard to the likelihood of policy reform in the future through rule changes that will apply during this regulatory period.

Currently, competition in metering is limited to large customers in the national electricity market while regulated distributors have the sole responsibility to provide small customers with metering services.¹

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

The AEMC published its draft rule on 26 March 2015. It provides that the AER should determine 'the arrangements for a DNSP to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.² 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

¹ NER clause 7.2.3(a). Small customers refers to any customer with less than 160MWh annual consumption (effectively all residential and small business customers fall into this category).

² AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

- requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.³

Our preliminary decision takes the AEMC’s draft rule into account and establishes a regulatory framework for the 2015-20 regulatory period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.⁴ This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

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

16.1.1 Preliminary decision

16.1.1.1 Structure of metering charges

Consistent with our framework and approach decision, we classify type 5 and 6 metering services and exceptional large customer metering services as alternative control services.⁵ Our metering assessment in this chapter does not include meter testing at the request of the customer and large customer meter provision and energy data services (type 1 to 4 metering installations) because these are classified as negotiated distribution services.⁶

The control mechanism for alternative control metering services will be caps on the prices of individual services.⁷

Our preliminary decision approves two types of metering service charges:

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

We do not approve meter exit or transfer fees.

Figure 16.1 depicts how the two regulated annual charge components relate to different metering customers.

³ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. iii.

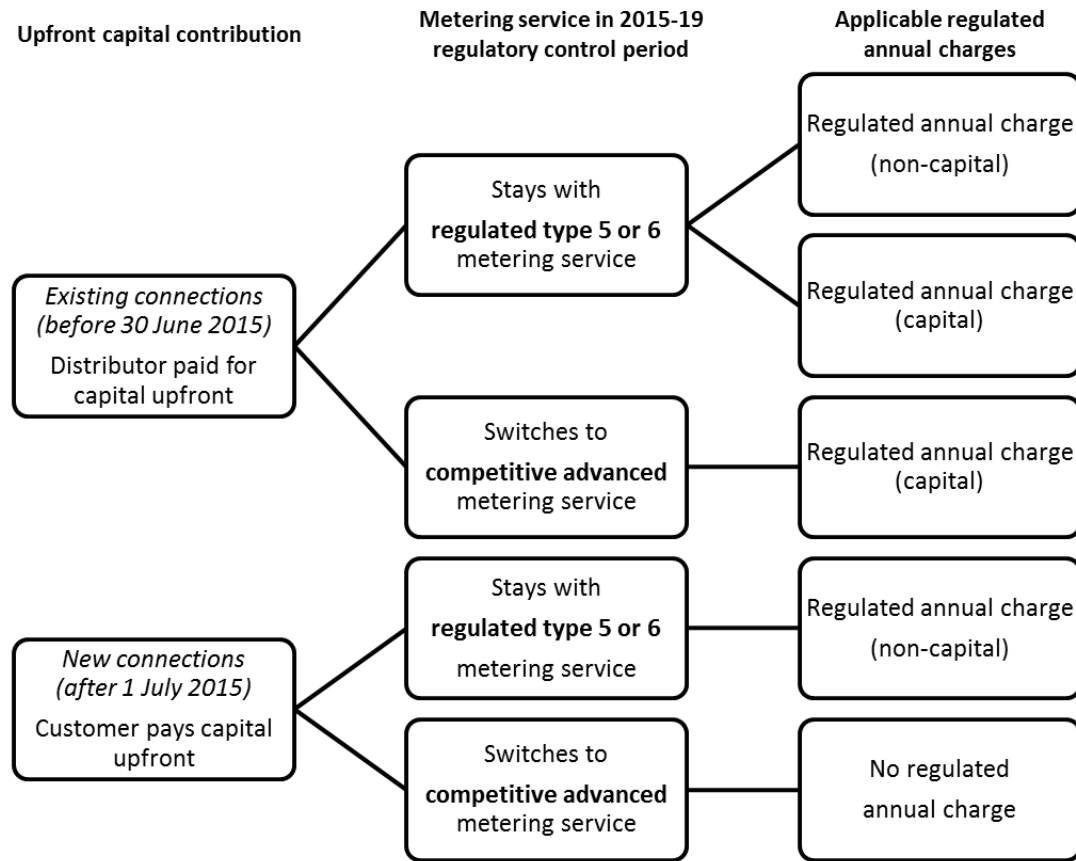
⁴ AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 79.

⁵ AER, *Final framework and approach for SA Power Networks*, April 2014, p. 38.

⁶ AER, *Final framework and approach for SA Power Networks*, April 2014, p. 37.

⁷ AER, *Final framework and approach for SA Power Networks*, April 2014, p. 39.

Figure 16.1 – 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 recovery⁸) component of regulated annual metering charge
- Non-capital (opex and tax) component of the regulated annual metering charge.

⁸ The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–20 regulatory control period to include forecast replacement capex. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

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

- Capital component of the regulated annual metering charge.

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

- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.1.

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

New connections (after 1 July 2015)

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

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

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

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

- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.1.

16.1.1.2 Annual metering charges

We generally accept SA Power Networks' building block approach as the basis for establishing annual metering charges but not the proposed values of particular building blocks:

- **Opening metering asset base**

Our preliminary decision is to accept the proposed opening metering asset base (MAB) value as at 1 July 2015 of \$85.3 million (\$nominal).⁹

- **Depreciation**

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

We also confirm that forecast, as opposed to actual, depreciation will apply to the roll forward of SA Power Networks' MAB at the next regulatory control period.

- **Forecast capex**

We do not accept SA Power Networks' proposed forecast capex. Our preliminary decision allows \$10.6 million in capital expenditure for annual metering charges instead of SA Power Networks' proposed \$42.7 million (\$2014-15). Of the capital expenditure we have not accepted, approximately 45 percent (or \$12.4 million) relates to our preliminary decision to move the cost recovery of new connections from the annual metering charge to upfront payments. That is, SA Power Networks will still be able to recover this expenditure, but via a different capitalisation policy. The remaining capital expenditure we have not accepted relates to our assessment of SA Power Networks' proposed unit costs and forecast volumes (see section 16.1.5.2.3).

- **Forecast opex**

We do not accept SA Power Networks' forecast operating expenditure. In developing our alternative metering opex forecast, we used the 'base-step-trend' approach, rather than SA Power Networks' bottom up method. Our cost assessment led us to substitute \$34.9 million in operating expenditure for annual metering charges in place of the proposed \$85.6 million (\$2014-15). This was primarily because we did not accept SA Power Networks' proposed step change to move to monthly meter reads.

Based on our cost assessment of the individual building blocks and requirement that SA Power Networks establishes separate annual charges for new customers, we

⁹ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 25.2B SAPN Post tax revenue model ACS metering*.

rejected SA Power Networks' proposed price caps for annual charges. Our substitute price caps are set out in Appendix A.

16.1.1.3 Upfront capital charges

We generally accept SA Power Networks' proposal for the establishment of upfront capital charges. However, our preliminary decision makes adjustments to two aspects of SA Power Networks' proposal. These relate to:

- (1) the values of the proposed upfront capital charges
- (2) an expansion of the costs recovered under the proposed upfront capital charges.

Our preliminary decision on the values of the proposed upfront capital charges is based on our assessment of the proposed unit costs. We found that the proposed costs for Type 6 meters were above our observed market rates so we made adjustments, accordingly.

We do not accept the limited costs which SA Power Networks proposed to recover under its upfront capital charges. More specifically, SA Power Networks proposed to recover the cost of new connections via the annual metering charge, but use upfront capital charges to recover the cost of upgraded connections. We do not consider this to be an efficient structure for metering charges. We have thus expanded the costs recovered under the proposed upfront capital charges. This is to include the cost of both upgraded *and* new connections.

16.1.1.4 Metering exit fees

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

We do not approve SA Power Networks' proposal to recover administration costs relating to customers transferring to alternative metering providers through an exit fee. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

Therefore, no metering exit fee applies.

16.1.1.5 Control Mechanism

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

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

Where:

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

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

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year $t-2$ to December in year $t-1$. For example, for the 2015–16 year, $t-2$ is December 2013 and $t-1$ is December 2014 and in the 2016–17 year, $t-2$ is December 2014 and $t-1$ is December 2015 and so on.

A_i^t is zero

X_i^t is:

for the annual metering charges, the factors set out in Table 16.1

for the upfront charges, the factors set out in Table 16.2.

Table 16.1 X-Factors for annual metering charges (percent)

	2016–17	2017–18	2018–19	2019–20
X factor	0	0	0	0

Source: AER analysis

Table 16.2 X-Factors for upfront capital charges (percent)

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

Source: AER analysis

For the avoidance of doubt, when setting the prices for 2015–16, p_i^t are prices being set for year 2015–16 and p_i^{t-1} are prices from the year 2014–15.

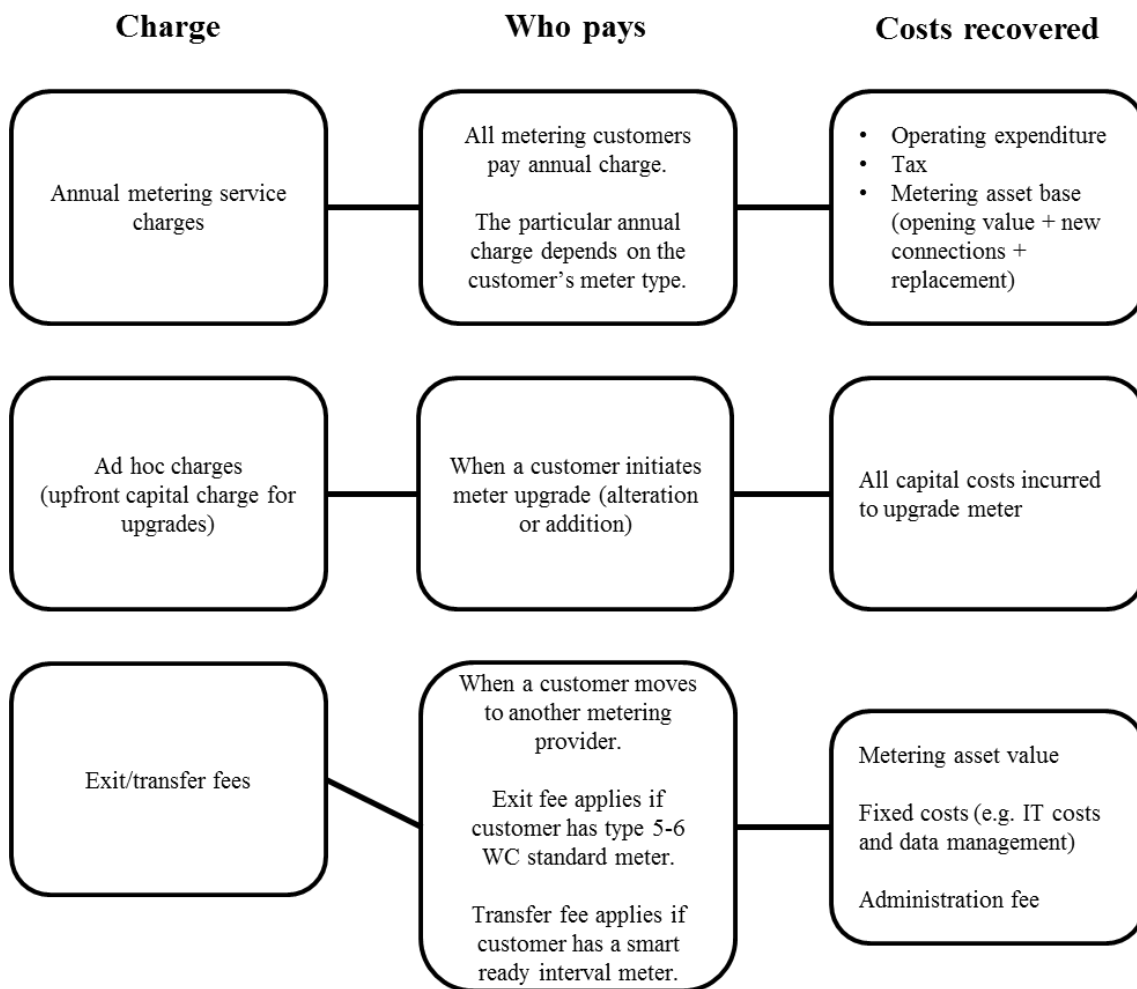
We will check for compliance with the control mechanism during the annual pricing process. To be compliant, SA Power Networks must annually adjust individual price caps in accordance with the control mechanism formula shown above. Further, SA Power Networks must show that individual prices are less than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

16.1.2 SA Power Networks' proposal

16.1.2.1 Structure of metering charges

SA Power Networks has proposed price caps on three categories of metering charges: annual metering charges, ad hoc charges (upfront capital charges for meter upgrades), and meter exit/transfer fees.¹⁰

Figure 16.2 - SA Power Networks' proposed structure for metering charges



SA Power Networks proposed that a customer who pays a one-off charge to upgrade their meter will, upon switching to an alternative metering provider, pay the standard meter exit fee (rather than the higher smart ready transfer fee).¹¹

¹⁰ SA Power Networks, *Regulatory proposal, Attachment 29.3*, October 2014, p. 5.

¹¹ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.3 ACS Metering Tariff Development Methodology*, p.13.

16.1.2.2 Annual metering service charges

For each meter type, SA Power Networks proposed a price cap for annual metering services. It built up the costs that constitute the annual metering service charges by applying a 'building block' approach. This involved forecasting the revenue requirement for each of the metering cost categories and then translating this into price caps. Table 16.3 shows the proposed metering building block requirement. Table 16.4 shows the proposed annual charges for metering services that recover the total proposed revenue.

Table 16.3 - SA Power Networks' proposed metering building block requirement

(\$ million, nominal)	2015–16	2016–17	2017–18	2018–19	2019–20
Return on capital	6.5	6.8	7.1	7.5	7.7
Return of capital	6.1	7.0	7.9	9.5	10.5
Operating expenditure	10.4	11.0	22.7	24.1	25.7
Tax liability	3.3	4.0	5.6	5.7	6.0
Total unsmoothed revenue	26.4	28.9	43.3	46.7	49.9

Source: SA Power Networks, *Regulatory Proposal 2015-20*, Table 29.7, p. 355.

Table 16.4 - SA Power Networks' proposed annual metering service charges

(\$/year, nominal)	2015–16	2016–17	2017–18	2018–19	2019–20
Annual charge (Type 1-4 'Exceptional' Remotely Read Interval Meter)	470	489	508	528	549
Annual charge (Type 5-6 CT Connected Manually Read Meter)	256	266	277	288	299
Annual charge (Provision Reading and Data Type 5-6 WC Manually Read Meter)	33	37	41	45	49

Source: SA Power Networks, *Regulatory Proposal 2015-20*, Table 29.9, p. 356.

SA Power Networks has proposed a significant new tariff and metering program which they suggest will meet the challenges of transitioning from:

a one-way energy distribution system to an active two-way grid that connects a dynamic web of distributed consumption and generation resources¹²,

¹² SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 3.

by:

- transitioning to more cost-reflective network tariffs. The new tariff is based on maximum demand and will be introduced on an opt-in basis from July 2015. From July 2017, SA Power Networks proposes to make this tariff mandatory for all new connections and customers choosing to upgrade their supply arrangements (for example, moving to solar PV)¹³
- installing smart ready interval meters as the standard meter for new and replacement installations
- upgrading some smart ready interval meters to have a telecommunications module to monitor power quality in the low voltage network.

The three cost components related to the above tariff and metering program that feed into alternative control metering service charges are:

- Installing smart ready interval meters as the default meter for new and replacement meter situations (forecast capital expenditure—\$11.0 million)
- IT costs for handheld meter reading devices (forecast capital expenditure—\$2.5 million)
- Monthly meter reads (operating expenditure step change—\$25.5 million).

Other costs related to the tariff and metering program include upgrading smart ready meters to be remotely read to enable power quality and other operational benefits. It also includes new IT systems. These IT capital costs are discussed in Attachment 6 (capex).

16.1.2.3 Upfront capital charges

SA Power Networks proposed ad hoc installation charges for a customer initiated meter alteration or addition. These would be upfront charges to recover all the costs incurred in providing a meter upgrade (instead of adding to the metering asset base and recovering annually).

Table 16.5 - SA Power Networks proposal - Ad hoc installation charges for customer upgrades

(\$, nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Type 5-6 WC Smart Ready Manually Read Meter (1 phase)	252	252	252	252	252
Type 5-6 WC Smart Ready Manually Read Meter (1 phase, 2 element)	259	259	259	259	259
Type 5-6 WC Smart Ready Manually Read Meter (3 phase)	383	383	383	383	383

¹³ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 3.

(\$, nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Type 5-6 CT Smart Ready Manually Read Meter (3 phase)	628	628	628	628	628

16.1.2.4 Meter transfer and exit fees

SA Power Networks proposed transfer fees for smart ready meters and an exit fee for basic type 5 and 6 whole current meters. SA Power Networks proposed to charge these exit/transfer fees when a customer switches to an alternative metering provider. These fees include stranded MAB recovery¹⁴, associated tax and other fixed operating expenditure (such as corporate overheads, contracted IT and meter data management costs).¹⁵ It also includes an administrative component of \$69.50 to process a customer transfer.

Table 16.6 SA Power Networks' proposed meter transfer and exit fees

(\$, nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Transfer Fee Type 1-4 Exceptional Meter	583	576	569	562	555
Transfer Fee Type 5-6 CT Connected Meter	261	257	254	251	248
Transfer Fee Type 5-6 WC Smart Ready Meter (1ph)	303	299	296	292	289
Transfer Fee Type 5-6 WC Smart Ready Meter (3ph)	550	543	536	529	522
Exit Fee Type 5-6 WC Standard Meter	212	210	207	204	202

Source: SA Power Networks, *Regulatory Proposal 2015-20*, Table 29.9, p. 356

16.1.2.5 Control mechanism

SA Power Networks proposed using an A-factor to adjust the price caps to capture costs outside of the distributor's control or too uncertain to be efficiently factored into the regulatory proposal. SA Power Networks envisages this A-factor could be used for:

the recovery of residual charges when customers choose to replace assets before the end of their economic life, the impacts of the annual updating of cost

¹⁴ MAB recovery is a component of SA Power Networks' proposed annual charges. If a customer switches to an alternative metering provider and stops paying annual charges to SA Power Networks, the portion of MAB recovery attributed to that switching customer would become stranded unless there is an alternative way to recover those costs, such as through a meter exit fee.

¹⁵ SA Power Networks, *Regulatory Proposal 2015-20*, p. 357.

of debt or of the otherwise unrecoverable costs associated with extraordinary customer churn.¹⁶

SA Power Networks propose to demonstrate compliance with the control mechanism by:

...proposing tariffs that comply with the price cap formula with its pricing proposal in May of 2015, and in each year of the next RCP [regulatory control period].¹⁷

16.1.3 AER's assessment approach

Our assessment approach first considered SA Power Networks' proposed structure of metering services. We then considered SA Power Networks' proposed costs, tailoring our assessment approach according to each type of charge.

16.1.3.1 Structure of metering charges

AEMC's draft rule change does not specify a method, but considered that the AER should determine how distributors recover residual capital costs of its regulated metering service in accordance with the existing regulatory framework.¹⁸

We also considered requirements in the NER. In particular, the service classification and control mechanism factors.¹⁹ 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 16.7 sets out the factors which we have considered.

Table 16.7 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	The desirability of a consistent regulatory arrangements to similar services (both within and beyond the relevant

¹⁶ SA Power Networks, *Regulatory Proposal 2015-20*, p. 171.

¹⁷ SA Power Networks, *Regulatory Proposal 2015-20*, p. 356.

¹⁸ AEMC, *Draft Rule Determination (Expanding competition in metering and related services)*, 26 March 2015, p. 225.

¹⁹ NER, cl. 6.2.2(c) and cl. 6.2.5(d).

Classification factors	Control mechanism factors
jurisdiction)	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).

The desirability for consistency between regulatory approaches and arrangements is both a classification and control mechanism factor. In taking these factors into account, we considered our determinations on the NSW ACT 2014–15 and 2015–19 regulatory control periods. In those determinations we approved a structure of metering services which included separate charges for existing and new or upgraded customers.

We also had regard to the revenue and pricing principles in the national electricity law which include providing a distributor with a reasonable opportunity to recover at least its efficient costs.²⁰

16.1.3.2 Annual metering service charges

We assessed SA Power Networks' proposed opex and capex components associated with the annual metering service. This is together with the proposed opening MAB value and the approach SA Power Networks' put forward for depreciation.

16.1.3.2.1 Opening metering asset base

In assessing the proposed opening MAB value, we reviewed how SA Power Networks had separated its proposed opening metering asset base (MAB) as at 1 July 2015 from the RAB for standard control services.

16.1.3.2.2 Depreciation

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

16.1.3.2.3 Forecast capital expenditure

In assessing the proposed forecast capital expenditure, we firstly assessed SA Power Networks' proposal to install smart ready interval meters as the default meter for replacement situations.²¹ We considered the following:

- any legislative or regulatory requirements regarding meter type

²⁰ NEL, Revenue and Pricing Principles, 7A (2).

²¹ Due to our preliminary decision on the structure of metering charges, new installations will be charged upfront to the customer. A customer will be able to choose their meter type.

- the relative business costs and benefits of installing smart ready interval meters instead of accumulation meters
- the wider market costs and benefits to assess whether the roll out of smart ready interval meters is in the long term interests of consumers.

We then reviewed SA Power Networks' 'unit costs' and 'volume forecasts'. More specifically, we assessed the proposed:

- 'material' and 'non-material' unit costs²²
- volume of 'reactive' and 'proactive' replacements.

16.1.3.2.4 Forecast operating expenditure

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

To develop our alternative forecast for metering operating expenditure, we used a top-down 'base, step and trend' approach which we explain further below. This differs to the 'bottom up' approach used by SA Power Networks. It derived its unit costs for operating expenditure activities; specifically, meter reading, meter maintenance, and meter data services.²³ SA Power Networks then applied those unit costs to its forecast volumes for each activity.²⁴

16.1.3.2.4.1 Base

As operating expenditure is largely recurrent in nature, we considered SA Power Networks' historical costs to be a useful starting point to establish a base to forecast future costs. We also used benchmarking to assess the relative efficiency of the base year compared with comparable network businesses in the national electricity market.

Our base assessment uses historical data over a five year period, rather than selecting a single base year. Given that we do not apply an efficiency benefit sharing scheme (EBSS) to alternative control services, we consider an average of multiple years to be a better measure of a business' efficient base; it avoids any incentive to 'load' a single base year with expenditure going forward.

We used 'opex for metering' data collected in our economic benchmarking regulatory information notices (RIN). This audited data is suitable for comparison because the

²² Material costs relate to the hardware used to provide metering services. Non-material costs relate to the labour activities which SA Power Networks must perform in order to replace a meter.

²³ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.3 ACS metering tariff development methodology*, October 2014, p. 9–11.

²⁴ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.3 ACS metering tariff development methodology*, October 2014, p. 9–11.

data provided by the distributors was prepared according to a consistent set of instructions and definitions.²⁵

Our metering assessment relates to annual charges for default type 5 and 6 metering services common to all regulated metering customers. In some jurisdictions, there are also ancillary metering services paid for by customers specifically requesting a service like an off-cycle meter read or a meter accuracy test. However, the economic benchmarking metering opex data does not distinguish between ancillary and default metering services. Thus, we adjusted base metering operating expenditure data to exclude ancillary metering service costs. For SA Power Networks, we included historic type 5 maintenance costs which have previously been a negotiated distribution service.

With this adjusted base data, we then performed our benchmarking analysis. We used a partial performance indicator for our benchmarking analysis. This compared historic annual metering opex per customer across non-Victorian distributors²⁶ in the national electricity market.

Our benchmarking analysis for metering is a simpler version than what we used to assess standard control opex. This reflects the generally lighter handed regulatory approach to alternative control services compared with standard control services. For example, our econometric modelling results we used to assess standard control opex were based on data for network services and therefore do not strictly apply to metering services.

We then adjusted the benchmarking results for customer density. This is a network characteristic that is an exogenous influence on operating expenditure requirements.

16.1.3.2.4.2 Step changes

When assessing a distributor's proposed step changes, we considered whether they are needed for the total opex forecast to reasonably reflect the opex criteria.²⁷ Our assessment approach is consistent with our *Expenditure forecast assessment guideline*.²⁸

We generally consider an efficient base level of opex is sufficient for a prudent and efficient distributor to meet all existing regulatory obligations. This is the same regardless of whether we forecast an efficient base level of opex based on the service provider's own costs or the efficient costs of comparable benchmark providers. We only include a step change in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex.

²⁵ AER, Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample, November 2013.

²⁶ Victorian distributors rolled out advanced metering technology in the last regulatory period. These costs are not comparable to other distributors which have type 5 and 6 meters.

²⁷ NER, clause 6.5.6(c).

²⁸ AER, *Expenditure assessment forecast guideline*, November 2013, p.11, 24.

Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken.

16.1.3.2.4.3 Trend

We then trended forward base opex (plus any step changes) by considering forecast changes in output, price and productivity.

For both capital and operating expenditure, we had regard to the capital and operating expenditure objectives and criteria in chapter 6 of the NER.²⁹ Though these considerations relate to standard, as opposed to alternative, control services, they are helpful and relevant in providing a general framework for assessing a building block expenditure forecast. Among other things, when considering a distribution business's forecast, the capital and operating expenditure objectives and criteria state we should consider:

- the efficient costs required
- the costs a prudent operator would incur
- whether the proposed cost inputs are realistic.³⁰

16.1.3.3 Upfront capital charge

To assess the reasonableness of the proposed charges from 1 July 2015, we analysed SA Power Networks' unit costs. We did not consider the forecast volumes of new or upgraded connections for the 2015–20 regulatory control period; they have no bearing on the quantum of the upfront charge.

16.1.3.4 Metering exit fees

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

With regard to the administration component of the proposed exit fee, we must balance revenue recovery for the efficient costs of the distributor's service provision with identifying and removing barriers to entry and competition, consistent with the proposed metering rule change submitted by the COAG Energy Council and currently being deliberated by the Australian Energy Market Commission.³¹

We undertook a cost assessment underlying the proposed meter transfer fees to determine the efficiency of those costs. To assess costs we considered the activities either required, or reasonably expected to be required, for a meter transfer, by both a

²⁹ NER, cl. 6.5.6 and 6.5.7.

³⁰ NER, cl. 6.5.6(c) and 6.5.7(c).

³¹ Australian Energy Market Commission, Draft rule determination, Expanding competition in metering and related services, 26 March 2015.

distributor and a competing metering provider. We had regard to the costs estimated to be incurred from such activities in New South Wales, the Australian Capital Territory, Queensland and South Australia. Victorian distributors are under a State Government mandated smart meter roll out, and so meter transfer is not a comparable activity that can be presently undertaken and therefore benchmarked.

We consulted with first and second tier retailers and the Australian Energy Market Operator to ascertain those activities necessary for the efficient transfer of meter customers among service providers. The New South Wales and Australian Capital Territory distributors' revised revenue proposals, and the initial proposals from Queensland and South Australia's distributors, outlined the activities they would undertake to transfer customers.

16.1.4 Interrelationships

Our preliminary decision should provide SA Power Networks with an opportunity to recover at least its efficient costs.³² This includes, where relevant, providing enough expenditure for the business to repay its debt financing costs and earn a reasonable return on its investments.

Our preliminary decision on SA Power Networks' alternative control metering proposal, therefore, interrelates with our assessment of its proposed rate of return. Refer to attachment 3 of this preliminary decision for the rate of return we accept for direct control services,³³ along with our reasons. Unlike standard control services, we will not be annually adjusting for the return on debt for alternative control services. The only annual changes for price caps for alternative control services will be consistent with our price control mechanism formula set out in 16.1.1.5.

16.1.5 Reasons for preliminary decision

Our reasons for not accepting SA Power Networks' proposed structure of metering charges, annual metering services charge, ad hoc charges, and the exit fee are discussed in this section.

16.1.5.1 Structure of metering charges

Our preliminary decision approves two types of charges:

- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising two components
 - Capital—metering asset base (MAB) recovery

³² NEL, Revenue and Pricing Principles, 7A (2).

³³ Direct control services are defined in Chapter 10 of the NER to include standard and alternative control services.

- non-capital—operating expenditure and tax.

We approve an upfront capital charge for two reasons. Firstly, it directly attributes the capital costs to the customer who initiates the meter installation. Secondly, it is appropriate in the context of expanding competition in metering. It is difficult to forecast the number of new regulated type 5 and 6 meters that will be installed in the upcoming 2015–20 regulatory control period. By charging upfront, we avoid having to forecast capital expenditure for new and upgraded metering installations that may not eventuate.

To better meet the distribution pricing principles, it important for annual charges to be set on a cost-reflective basis. It is particularly significant in the context of expanding competition in metering. By setting cost-reflective regulated metering charges, customers will be able to compare the costs of their current regulated service with offers from alternative metering providers when competition begins.

We consider that a cost-reflective annual charge for new metering connections installed after 1 July 2015 should only consist of non-capital costs (operating expenditure and tax). This is because the capital cost of meters installed after 1 July 2015 would have been fully customer funded. In contrast, pre 30 June 2015 customers on a regulated metering service who have not paid for the meter upfront should contribute to the MAB recovery through their annual charge. That is, they pay a cost-reflective annual charge that includes both capital and non-capital components. This is the way such customers pay for their regulated metering services now.

However, if a customer chooses to switch to a competitive metering provider, the capital component of the annual charge would become stranded for the distributor. That is unless there is a mechanism for recovering that cost. It is important to recognise that customers pay the capital costs of a meter on an annual basis, they represent an amortised cost (that is, have been paid for upfront by the distributor and then recovered gradually over time from customers). Past capital expenditure is a fixed cost because it does not vary with how many customers switch; the capital costs have already been incurred by the distributor to provide a regulated metering service. This is in contrast to metering operating expenditure, such as meter reading costs, which are largely variable. This means the distributor can avoid those costs if a customer switches.³⁴

QCOSS considers *"it would be inappropriate to recover residual costs associated with a service that customers are not getting any benefit from.... distributors should not be allowed to recover such costs from consumers - either through a charge which is allocated across all customers nor via individual exit fees."*³⁵ But this effectively means that the distributor would be unable to recover the undepreciated residual value of those meters. The revenue and pricing principles provide that distributors should have

³⁴ Although the capital costs of the meter remain to be recovered by the distributor, there is no longer any need to read the meter, thus providing an opex saving.

³⁵ QCOSS Submission to AER Consultation Paper (Recovery of Residual Metering Costs), 31 March 2015, p 2

a reasonable opportunity to recover at least their efficient costs. We therefore consider it appropriate that distributors recover their fixed capital costs that were incurred in providing regulated metering services.

Accordingly, we considered the most appropriate way to recover metering capital costs incurred in providing regulated metering services that risk becoming stranded if a customer switches.

SA Power Networks stated it considered various alternatives to exit fees, but felt that the exit fee option was congruent with the Standing Council on Energy and Resources' (now CoAG Energy Council) expanding competition in metering and related services rule change proposal.³⁶ There has been significant progress since SCER initiated its rule change request in October 2013, with the AEMC having released its draft rule change determination on 25 March 2015.

In its draft rule change, the AEMC confirmed that "the arrangements for a DNSP to recover the residual costs of its regulated metering service should be determined by the AER in accordance with the existing regulatory framework."³⁷ They note that relevant aspects of the regulatory framework include the NEO, the revenue and pricing principles, as set out in section 7A of the NEL, distribution pricing principles, as set out in rule 6.18 of the NER and the provisions regarding the classification of distribution services and applicable control mechanism, as set out in rule 6.2 of the NER.³⁸ These are the criteria we have considered in making our preliminary decision.

Various stakeholders raised concerns that a large upfront exit fee would be a barrier to competitive entry and to the take up of advanced metering.³⁹ In particular, it potentially creates a first mover disadvantage because a market-led smart meter rollout is predicated on the customer not having to pay any charges upfront.⁴⁰ Therefore, the first mover competitive metering provider may have to pay for both an exit fee as well as the new smart meter—and bear the risk of those sunk costs if the customer decided to move to another competitive metering provider. We find that exit fees create a regulatory barrier to a market-led roll out of advanced metering.

There are several methods of ensuring distributors can recover capital costs incurred in providing regulated metering services. After extensive consultation with

³⁶ SA Power Networks, *Regulatory Proposal 2015-20*, p. 171.

³⁷ AEMC, Draft Rule Determination (Expanding competition in metering and related services), 26 March 2015, p. 225.

³⁸ AEMC, Draft Rule Determination (Expanding competition in metering and related services), 26 March 2015, p. 225.

³⁹ Consumer Challenge Panel, Updated submission on NSW DNSPs regulatory proposals 2014-19, 15 August 2014, pp. 36-7.

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

ERAA, Submission on Issues paper NSW electricity distribution regulatory proposals, 8 August 2014, p. 2.

Origin Energy, Submission on NSW electricity distributors regulatory proposal (attachment 1), 8 August 2014, p. 33.

AGL, Submission on NSW electricity distribution networks regulatory proposals, 8 August 2014, p. 21.

PIAC, Submission on NSW electricity distribution network price determination, 8 August 2014, p. 105.

⁴⁰ Vector Limited, Submission on DNSPs regulatory proposals, 8 August 2014 p. 4.

stakeholders⁴¹, we decided on a method that we considered best balances the objectives of distributors and customers and meets regulatory objectives to promote competition in metering services.

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

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

We consider our preliminary decision to have switching customers continue to pay for the capital costs associated with the regulated metering service better meets the regulatory objectives under the NEL and NER, than SA Power Networks' proposal. We considered:

- Impact on competition
 - Our preliminary decision removes the upfront exit fee which was identified as the primary barrier to competitive entry by stakeholders
 - Our preliminary decision removes concerns about first mover disadvantage that would arise if the first mover had to pay the upfront exit fee and risk being undercut by another competitive provider that does not face the exit fee. Under the preliminary decision, the customer is charged the capital component of the regulated annual metering charge directly.
- Administrative simplicity

⁴¹ In addition to our normal consultative process which allows stakeholders to provide submissions on the distributor's proposal and our draft decision, we also held a metering workshop on 11 September 2014 and released a consultation paper (on the alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge) in March 2015. We received submissions from consumer groups, potential competitive metering providers, retailers and distributors.

- Our preliminary decision makes use of existing information that SA Power Networks has, rather than relying on further information on the remaining economic or technical life of individual metering assets which would be difficult to determine.
- The directly attributed cost to minimise cross subsidies
 - Our preliminary decision involves continuing to charge switching customers an ongoing regulated annual charge to recover metering capital costs associated with their past regulated metering service. We considered whether it was appropriate to continue to charge a regulated annual charge when a customer is no longer receiving an active regulated metering service. We consider that it is appropriate to charge switched customers for fixed capital costs associated with their past regulated metering services because it more directly attributes cost recovery to the customer group that caused those costs to be incurred and ensures that the distributor has an opportunity to at least recover its efficient costs. We consider this also strikes an appropriate balance to promote efficient investment as set out in the revenue and pricing principles
 - Under our preliminary decision, only customers at premises which currently or previously had a regulated metering service will be paying for the capital costs incurred in providing regulated metering services
 - Nonetheless, our preliminary decision still involves some cross subsidy. This is because the capital component of the annual charge is based on the average depreciated value of the MAB. We consider this is appropriate given that we do not have granular information on the customer's specific meter asset type or age
 - Another form of cross subsidy is that the regulated annual charge (capital) a switching customer will pay for includes some recovery of forecast replacement capital expenditure that is not linked to the switched customer's past regulated metering service. The opening MAB value is based on past capital expenditure. The MAB is not forecast to grow much because from 1 July 2015, all new and upgraded meters will be paid for upfront and will therefore not be included in the MAB. However, some forecast capital expenditure relating to replacement meters will be added to the MAB.⁴² However, this is expected to be an interim issue as it is likely that distributors will not be able to install replacement meters after the metering rule change comes into effect on 1 July 2017⁴³

⁴² Capital expenditure related to replacement meters is added to the MAB and recovered from all metering customers through the annual charge, rather than charged upfront. We consider this is appropriate because replacement is not initiated or controlled by the customer. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

⁴³ AEMC, Expanding competition in metering and related services, Draft Rule Determination, 26 March 2015, p. 79.

- Our preliminary decision to charge for new and upgraded meters upfront removes the risk of future cross subsidy. This is because by charging capital costs upfront, it is directly attributed and paid for by the customer choosing to install that meter. There is no risk of metering capital costs becoming stranded.

16.1.5.2 Annual metering services

Our preliminary decision is to not accept SA Power Networks' total proposed building block requirement for annual metering services. We accept a building block approach to setting charges and the proposed opening MAB, but not the following components of SA Power Networks' proposal:

- forecast capex
- forecast opex.

SA Power Networks proposed significant change to its tariff and metering program in the 2015-20 regulatory period. The costs associated with this program feed into both opex (monthly meter reads) and capex (installing smart ready interval meters and IT capex for handheld meter reading devices) components of the annual metering charges.

The Consumer Challenge Panel 2 considered that 'it is not appropriate for the AER to allow such expenditure when there is so much policy uncertainty – and certainly no specific regulatory requirement – at this stage'.⁴⁴ Until policy and rules have been finalised the CCP2 'urges the AER to adopt a cautious approach to providing capex and opex allowances for SAPN's "smart ready" meter program and associated demand tariffs and monthly meter reading'.⁴⁵ AGL echoed these sentiments in their submission and state that '[o]ur summary perspective is that, in the absence of clear policy guidance, SAPN have taken the opportunity to propose an arrangement that will maximize their likely share of the future metering market'.⁴⁶

While we agree with SA Power Networks that the industry is changing and we fully support the transition to more cost-reflective tariffs as it is consistent with the recent distribution pricing rule change made by the AEMC, we share the concerns raised by the CCP2 and AGL.

We do not consider SA Power Networks' proposed tariff and metering reform package is appropriate ahead of metering competition. As well, we consider that smart ready interval meters and monthly meter reads are only marginal improvements on the status quo (of accumulation meters and quarterly meter reads); the real move towards cost-

⁴⁴ Consumer Challenge Panel 2, Submission by Consumer Challenge Panel 2 to the AER in response To SA Power Networks Regulatory Proposal For 2015-2020, 2 Feb 2015, p. 48.

⁴⁵ Consumer Challenge Panel 2, Submission by Consumer Challenge Panel 2 to the AER in response To SA Power Networks Regulatory Proposal For 2015-2020, 2 Feb 2015, p. 48.

⁴⁶ SA Council of Social Services (SACOSS) - Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 34.

reflective pricing will be facilitated through advanced metering which is capable of remotely reading real time data. As a package, SA Power Networks are proposing interim measures which are relatively costly in comparison to the limited benefits to be derived prior to any market-led roll out of advanced metering.

As a result, we have not accepted the opex step change for monthly meter reading or capex for smart ready interval meters and handheld metering devices. Our more specific reasons are discussed below.

Consequently, we reject SA Power Networks' proposed annual metering service charges. Our alternative price caps are set out in appendix A.

16.1.5.2.1 Opening metering asset base

Our preliminary decision is to approve an opening MAB value as at 1 July 2015 of \$85.3 million (\$nominal). In accepting SA Power Networks' proposed opening MAB we found that the proposed asset value complied with all regulatory requirements.⁴⁷ In particular, the calculated amount was consistent with changes made to the roll forward model for standard control services. For more information about those changes, see attachment 2 to this preliminary decision.

16.1.5.2.2 Depreciation

We accept SA Power Networks' method for developing its proposal for regulatory depreciation of the MAB. This involved using the AER's post tax revenue model which contains a specific depreciation calculation method.⁴⁸ We also confirm that forecast, as opposed to actual, depreciation will apply to the roll forward of SA Power Networks' MAB at the next regulatory control period.

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

SA Power Networks proposed accelerated depreciation for meter reading devices.⁴⁹ We have not accepted the capital expenditure associated with the acquisition of those devices and therefore our preliminary decision need not address their asset lives.

16.1.5.2.3 Forecast capital expenditure

Our preliminary decision accepts \$10.6 million in capital expenditure for annual metering services compared to SA Power Networks' proposed \$42.7 million (2014–15).

⁴⁷ NER, S6.1.3(7).

⁴⁸ SA Power Networks, *Regulatory Proposal 2015-20*, November 2015, p. 343.

⁴⁹ SA Power Networks, *Regulatory Proposal 2015-20*, November 2015, p. 344. The proposed a three year depreciation schedule.

Most of the capital expenditure we have not approved in our preliminary decision (45 percent or \$12.4 million) relates to changing the cost recovery of new connections—from the annual metering service charge to upfront payments made directly to SA Power Networks by customers. As such, SA Power Networks should still recover its costs associated with new connections; however, this will occur via a different capitalisation policy. The remaining proposed capital expenditure we have not accepted relates to our assessment of SA Power Networks' proposed unit costs and forecast volumes.

Table 16.8 sets out SA Power Networks' proposed capital expenditure. It also shows our preliminary decision on each cost category.

Table 16.8 Proposed and substitute capital expenditure for metering annual services (\$ million 2014–15)

	Proposed	Unit cost adjustment	Volume adjustment	Preliminary decision
New connections	12.4	0.0	12.4	0.0
Reactive replacement	1.6	0.7	0.0	0.8
Proactive replacement	26.4	4.2	12.4	9.8
Information technology	2.4	0.0	2.4	0.0
Total	42.7	5.0	27.1	10.6

16.1.5.2.3.1 Meter type

In addition to our concerns about implementing metering reform ahead of a market-led roll out of advanced metering, we also base our decision to reject installing smart ready interval meters for the following reasons.

No regulatory requirement

There is no regulatory requirement on SA Power Networks to provide smart ready meters. SA Power Networks refers to a discussion paper released by the SA Government in 2014 which considers whether interval meters should be the default meter for new and replacement meters.⁵⁰ However, The SA Government has since made clear it intends for the new and replacement policy to work in conjunction with the rule change on expanding competition in metering and does not intend to finalise its new and replacement policy until after the AEMC's final determination on the rule change.⁵¹ The SA' Government's website states that: *'[i]n response to a number of similar queries, the Department of State Development (DSD) would like to clarify that*

⁵⁰ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 20.

⁵¹ <https://www.sa.gov.au/topics/water-energy-and-environment/energy/energy-providers-and-bills/advanced-electricity-meters-consultation>

the new and replacement metering policy is not proposing to mandate type 5 meters in all new and replacement situations under the existing framework, which would, in effect, require the roll-out of meters to be led by the local distribution network service provider.⁵²

Prudence and efficiency of interval meters vs accumulation meters

Although there is no regulatory requirement to install smart ready interval meters, a distributor can still choose to install these meters. We would expect that such a decision would be based on a compelling business case. In the lead up to metering contestability, we must consider whether providing the most basic accumulation (type 6) meter or installing smart ready manually read interval (type 5) meters is more prudent and efficient. This is in situations where a meter needs to be replaced because it has failed or has been identified as being part of a failed meter population which requires proactive replacement.⁵³

SA Power Networks notes that the additional cost to install a smart ready interval meter instead of a basic accumulation meter in replacement situations is \$93 (\$2014).⁵⁴ This results in an additional \$11.0m (\$2014-15) of capital expenditure.⁵⁵

SA Power Networks consider the benefit of installing smart ready interval meters is that it will facilitate more cost-reflective tariffs. In turn, cost-reflective tariffs will reduce inequitable cross subsidies and encourage more efficient demand-side investment.⁵⁶ However, SA Power Networks has not provided sufficient evidence to suggest that the benefits of the smart ready program will outweigh the costs of an additional \$11.0 million in capex. SA Power Networks have not quantified these benefits. Further, we have reservations about the potential materiality of any such benefits and whether these could in fact outweigh the potential costs, noting the following:

- The benefits from smart ready interval meters rely on customers moving onto cost-reflective tariffs. However, we note that customers who have their meter replaced are not required to move onto cost-reflective tariffs.⁵⁷
- While we support moving to greater cost reflectivity in pricing, we note that the sophistication of price signals enabled by a type 5 (interval) meter will still be

⁵² <https://www.sa.gov.au/topics/water-energy-and-environment/energy/energy-providers-and-bills/advanced-electricity-meters-consultation>

⁵³ SA Power Networks proposed rolling out smart ready interval meters for both new and replacement situations. However, our preliminary decision on the structure of metering charges means that all new meters will be paid for upfront rather than recovered through the annual charge. We consider it is customer choice whether they want a type 5 or 6 meter. Our discussion is therefore limited to meter type for replacement, which is part of the ongoing annual charge.

⁵⁴ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 30.

⁵⁵ This calculation is based on \$93 multiplied by 118,625 (sum of the proposed reactive and proactive replacement forecast volumes (see Table 16.10)). This amount of additional capex will vary depending on our related decisions on unit costs and forecast replacement volumes.

⁵⁶ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 36 - 38.

⁵⁷ SA Power Networks is only proposing that customer initiated changes such as new and upgrades to meter connections will trigger a move to a capacity tariff. Meter replacement is not customer initiated.

somewhat limited. These meters can record data in thirty minute intervals, allowing time varying pricing. However, as per accumulation meters, these type 5 interval meters still need to be manually read. Therefore, there will be a disconnect between prices and when customers receive their bills, limiting a customer's ability to respond to price signals. Even SA Power Networks' proposal to move from quarterly to monthly reads⁵⁸ results in a significant lag. In comparison, an advanced meter can be read remotely and provide real time data to customers which would better facilitate cost-reflective pricing and customer response.

- The 'smart ready' type 5 meters would still lock in significant meter reading costs on customers, as these would need to be read manually, as per an accumulation meter. This provides another reason for why there is a high cost threshold for any benefits of this program to surpass. This is compared with an advanced type 4 meter which would facilitate remote meter reading.

Therefore, there is not enough evidence of expected benefits to outweigh the additional \$11.0m capex required to install interval meters instead of accumulation meters in replacement situations over the 2015-20 regulatory control period.

Not in the long term interest of consumers

We do not consider there are longer term benefits of installing smart ready interval meters ahead of a market led roll-out of smart or advanced meters. The metering rule change is expected to come into effect in 1 July 2017 and it would be desirable for a smooth transition for customers to move to advanced metering, which can unlock benefits that cannot be realised with either accumulation or interval meters. These benefits include customers having more granular data to better understand and manage their usage, cost savings from moving to remote meter reads and more control over smart appliances.⁵⁹

Potential entrants to a competitive metering market raised concern for the longer term market impacts of installing smart ready meters before the new arrangements are implemented:

- Vector stated that *'[w]e do not support any policy that requires the installation of 'smart ready' meters. This type of policy would inhibit market competition and innovation, and increase costs without overriding consumer benefits.'*⁶⁰
- AGL had similar concerns: *'we do not support a 'smart ready' roll out of meters. Any roll out would be a violation of competitive neutrality; and could be seen as an attempt to use regulated funding to introduce a transient asset into a competitive market, and a breach of current distribution ring-fencing guidelines. A rollout of 'smart ready' meters would also be structurally inefficient, such that it could never*

⁵⁸ See Step changes for fuller discussion of monthly meter read step change.

⁵⁹ AEMC, Expanding competition in metering and related services, Information sheet - consumer benefits (<http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv>)

⁶⁰ Vector, Submission on QLD and SA distributors' regulatory proposals 2015-20, 30 Jan 2015, p. 2.

provide full smart metering benefits to customers at an equivalent price point within a competitive environment'.⁶¹

- Macquarie disagreed with SA Power Networks' claims that these meters could be upgraded stating *'the notion of retrofitting 'smart ready' meters is both technically and financially flawed'.⁶²*

We share stakeholder reservations about whether SA Power Networks' roll out of smart ready interval meters is future proof and will cater for market evolutions.

SA Power Networks claims that smart ready meters are capable of meeting national smart meter minimum functionality specifications once upgraded with a communications module. However, the AEMC's national minimum functionality specifications and AEMO's more detailed shared market protocols have not yet been finalised. There is a resultant high degree of risk that smart ready meters may not align with the national minimum specifications and/or the shared market protocols. The modular nature of the smart ready interval meters means it is probable that these meters will be able to be technically upgraded to meet the specifications—but this would incur costs in addition to the communications upgrade.

There are two paths to transition to advanced metering for replacement meters depending on whether we approve expenditure for smart ready interval meters or accumulation meters:

- Option A: Install a smart ready interval meter at the time of replacement.

Moving to smart metering will also involve returning to the customer's premises to add a communications module to complete the upgrade (and possibly further alterations to the meter firmware and/or hardware to comply with the minimum specifications and to meet the functionality desired by the competitive metering co-ordinator).

- Option B: Install an accumulation meter at the time of replacement.

Moving to smart metering will involve going to the customer's premises to take out the accumulation meter and replacing with an entirely new advanced meter.

⁶¹ AGL, Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 15.

⁶² Macquarie CAF, Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 2.

Table 16.9 - Relative costs of transitioning to advanced metering (starting with a smart ready interval meter or an accumulation meter)

Option A (smart ready interval meter)			Option B (accumulation meter)
Incremental cost of smart ready interval meter (in addition to the cost of a basic accumulation meter) ⁶³	\$93		
Communications module upgrade ⁶⁴	\$234	New advanced meter ⁶⁵	\$261
Total transition cost (Option A)	\$327	Total transition cost (Option B)	\$261

Table 16.9 only shows the different hardware costs. We assume labour costs will be similar across both options because both involved going back to the customer's premises to either upgrade or install a completely new advanced meter.

We note that this is a conservative estimation of the cost difference, and that the cost difference between options A and B may in fact be larger. For example:

- The transition cost for Option A represents a lower bound because there may be further costs if firmware/hardware alterations are required. Not only may there be firmware/upgrades necessary to meet the minimum specifications, there may be additional costs to upgrade the meter to meet market requirements. Metropolis notes that '[w]hen the communications module is installed, the meter will need to be re-programmed to support the hardware selected by the new Metering Provider (it cannot be assumed that the "smart ready" meter can be correctly pre-programmed given the array of communications modules available)'.⁶⁶
- In comparison, the transition cost for Option B is an upper bound at \$261. For our estimate average advanced meter cost, we used the average advanced meter costs of the Victorian distributors from 2013. It is probable that technological improvements will see costs much lower by the time the market begins to roll out advanced meters nationally from 2017.

As discussed above, unlocking greater benefits for consumers and the market would be reliant on most small customers in the NEM transitioning to smart meters. Further, based on the data presented here, despite the fact that option B involves entirely

⁶³ We are unable to provide the actual costs of a smart ready interval meter and an accumulation meters as SA Power Networks have claimed confidentiality over their metering pricing model. However, the relevant point is the difference in costs, and so the considering the incremental cost of a smart ready interval meter versus an accumulation meter is sufficient.

SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 30.

⁶⁴ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business case*, p. 52.

⁶⁵ AER analysis. Average approved 2013 advanced meter hardware costs for Victorian distributors.

⁶⁶ Metropolis, Submission on SA Power Networks' regulatory proposal 2015–20, 30 January 2015, p. 2.

replacing the meter when it comes time to move to smart metering, it appears to be a more cost-effective option than upgrading smart-ready interval meters. As a result, smart ready interval meters risk becoming redundant before the end of their technical life. It does not seem prudent to install more expensive smart ready interval meters that face the same risk of becoming redundant as a cheaper accumulation meter. Particularly as under the existing regulatory framework it is customers, not SA Power Networks, which would pay for the redundant metering capital costs as customers begin to switch to competitive metering providers.

Given the limited benefits in the interim and that this is not a cost-effective way to transition to advanced metering we approve replacement capital expenditure for basic accumulation meters only.

16.1.5.2.3.2 Unit costs

Material unit costs

We took a two-step approach to assessing SA Power Networks' proposed material unit costs:

1. We assessed the case on the appropriateness of providing type 5 'smart ready' meters on a new and replacement basis, under their proposed meter and tariff program, discussed in the previous section.
2. We also undertook a strictly quantitative and comparative assessment of the unit costs SA Power Networks put forward for each kind of meter it proposed to offer over the regulatory control period.
3. For our quantitative and comparative assessment, we used a report commissioned from Marsden Jacob Associates. This report considered the 'maximum rate that should be applied for each meter hardware category based on consideration of the rates applied across the business and a comparison against current market rates'.⁶⁷ These rates were sourced from online advertised prices and through direct engagement with major suppliers.⁶⁸ Marsden Jacob took into consideration volume discounts which would reasonably be expected to apply to metering hardware purchases.⁶⁹

Using the Marsden Jacob's report, we found that some of the SA Power Networks' proposed unit costs for single and three phase Type 6 meters are outside of the observed market rates. We do not accept the proposed unit costs for those meters and substitute them with our own. In each instance, our substitutes bring the unit costs within the observed market ranges; specifically, to the outer limits of what Marsden

⁶⁷ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

⁶⁸ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

⁶⁹ Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

Jacobs found to be reasonable. Because the proposed unit prices for SA Power Networks' metering hardware were provided to us in confidence, our preliminary decision does not list those proposed prices.

Non-material cost

In assessing SA Power Networks' proposed non-material unit costs we developed a range which we would be willing to accept. We also took the non-material unit costs of other non-Victorian distribution businesses in the national electricity market into account.

To devise our range for non-material unit cost, we applied a bottom-up approach. This involved estimating a reasonable hourly rate for a metering technician and an average time required to replace a meter. We also accounted for the time it would take to travel from site to site, as well as for overheads.

We accept SA Power Networks' proposed non-material unit costs. The proposed amount is within the limits we developed using our bottom up approach and, in addition, the lowest unit cost we have observed among the non-Victorian distribution businesses.

16.1.5.2.3.3 Forecast volumes

We do not accept SA Power Networks forecast volume of new connections. Our preliminary decision is to shift the cost recovery of new connections from the annual metering charge to upfront capital charges. This in effect sets the forecast volume of new connections to zero. Additionally, we accept the volume of reactive replacements for the 2015–20 regulatory control period and about 57 percent of the proposed number of proactive replacements. Table 16.10 sets out SA Power Networks forecasts against our preliminary decision.

Table 16.10 Forecast and approved volumes of meter replacements

	Forecast	Preliminary decision
New connections	52 500	0
Reactive replacements	10 324	10 324
Proactive replacements	108 301	61 480

Source: SA Power Networks, Regulatory proposal, Attachment 29.4, October 2014.

Note: SA Power Networks refers to reactive replacements as 'unplanned replacements' and proactive replacements as 'planned replacements'. We have used the reactive and proactive descriptions in place of SA Power Networks' terminology to maintain a consistency between other AER decisions.

In considering SA Power Networks' proposed forecast volume of replacements we took a number of stakeholder submissions into account. AGL noted that SA Power

Networks had proposed an 'aggressive meter replacement program'.⁷⁰ It further noted that 'the AER [should] closely review [SA Power Networks'] replacement program to ensure that meters are only replaced where they no longer meet metrology standards or have reached end of life'.⁷¹ The SA Council of Social Services commented that it 'is very concerned about the replacement volumes in this proposal and at this stage, does not support [SA Power Networks] proposal'.⁷²

New connections

Due to our required change in cost allocation, we do not accept any forecast volumes associated with new connections, but note that SA Power Networks should still be able to recover its costs. Consistent with previous AER decisions,⁷³ we consider there to be substantial benefits if SA Power Networks changes its capitalisation policy. This is so that the costs of installing meters at new connections are not recovered through the annual metering charge, but as upfront payments. In effect, this means that we do not need to consider forecast volumes of new connections, since they have no bearing on upfront payments. Hence we have not approved, or considered, any forecast volumes.

When implemented, our approach to SA Power Networks' capitalisation policy for new connections should help level the competitive playing field for new meters. This is by providing transparent standalone prices for all new or upgraded meter connections. It will also shift how SA Power Networks' capital costs are recovered. This is from the annual metering services charge, where costs are smeared across all customers, to an upfront payment which new entrants to the market are able to compete with in terms of price.

This change in capitalisation policy for new connections has a significant impact on the capex building block component of annual metering charges. Notwithstanding this, SA Power Networks will still be able to recover its costs. The only difference is that the cost of new connections will be recovered via upfront capital contributions, rather than as part of annual metering charges.

We therefore do not approve any of the forecast 52 500 new connections. However, this is so we can facilitate the reallocation of the cost recovery of new connections from the annual metering charge to upfront capital charges.

The charges our preliminary decision accepts for new connections are set out in appendix A.

⁷⁰ AGL, Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 16.

⁷¹ AGL, Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 17.

⁷² SA Council of Social Services (SACOSS) - Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 35.

⁷³ AER, *Draft decision on ActewAGL's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Ausgrid's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Essential Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014.

Reactive replacements

We accept the proposed reactive replacement volume of 10 324 meters. Reactive replacements are made in response to full functionality failure, such as physical damage, and are usually detected at a meter reading or other site visit. We consider such functionality failures to be statistically random in nature and consider that historical performance is a good indicator of future requirements. Our preliminary decision accepts the proposed volume forecasts because it reflects the number of reactive replacements which SA Power Networks made in the 2010–15 regulatory control period (9 840).⁷⁴

Proactive replacements

Our preliminary decision is to not accept the proposed proactive replacements. We have substituted SA Power Networks' forecast with an amount reflective of the distribution business' historical volumes.

Proactive replacements are driven by regulatory obligations under the NER and Australian Standard 1284.13. Together they create requirements on SA Power Networks' 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.⁷⁵ For Type 6 meters it is +/-2.0 percent.⁷⁶

Because it would be inefficient to test every meter in service against the accuracy limits in Chapter 7 of the NER, Australian Standard 1284.13 provides for a regime where smaller 'samples' of a much greater 'population' can be taken. The sample sizes vary according to the population size. For example, if 1 201 meters of a particular make and model are in service, then 125 samples have to be taken. But if more meters of a different make and model are in service, then the sample size must be greater. For example, a population of 150 001 meters requires a sample size of 800.

Significantly, Australian Standard 1284.13 sets out the 'acceptable quality level' for each sample. This is the number of meters in a sample which can fail the accuracy limits in Chapter 7 of the NER before the *entire* population is deemed to be recording energy usage inaccurately, to an extent that is considered unacceptable. In other words, when the acceptable quality level is exceeded it can be statistically deduced that the same error reading is spread across the entire population at a similarly high, intolerable rate.

The acceptable quality level varies with population size. For example, a population of 1 201 meters requires a sample size of 125, with an acceptable quality level of 10 at a full load.⁷⁷ The acceptable quality level with a population of 150 001 meters, on the

⁷⁴ SA Power Networks, *Regulatory proposal, Attachment 29.4*, October 2014.

⁷⁵ NER, S7.2.3.1.

⁷⁶ NER, S7.2.3.1.

⁷⁷ Australian Standard 1284.13.

other hand, is 21.⁷⁸ Importantly, where a sample belonging to a particular make and model breaches the acceptable quality limits, this must be remedied in a timeframe agreed with the Australian Energy Market Operator.⁷⁹ We accept that an efficient method to satisfy this regulatory obligation is to replace the entire population of meters; that is, to conduct proactive replacements.

We have previously proposed to approve proactive replacements.⁸⁰ However, this has only been if a distribution business has been able to support its forecast with sampling data.⁸¹ This data must show that the distribution business has conducted the required number of samples under Australian Standard 1284.13. It should also show that the required number of meters within that sample have failed the accuracy limits set out in Chapter 7 of the NER. That is, the acceptable quality level has been breached. Where we have not been provided with actual sampling data, our proposed decision has been not to approve the forecast volumes.⁸²

In the case of SA Power Networks, sampling data which supports its proactive replacement forecast is not available. In an information response to the AER, SA Power Networks stated that '[r]eplacements based on testing results are undertaken, as far as possible, in the year following the relevant testing'.⁸³ Thus, for example, 'the makes, models and numbers of meters to be replaced in 2015 are determined by reference to testing undertaken in 2014'.⁸⁴ This means that SA Power Networks' business practices are such that it has no data from actual samples taken, to support its proactive replacement volumes forecast for its upcoming five year regulatory control period.

Given the absence of data on actual samples conducted, we consider SA Power Networks' historical volumes to be the best available indicator of future requirements. Taking this approach, we trended forward the proactive replacements SA Power Networks conducted in the 2010–15 regulatory control period. This leads to a volume forecast of 61 480 proactive meter replacements, compared to SA Power Networks' proposed 108 301.

⁷⁸ Australian Standard 1284.13.

⁷⁹ NER, cl. 7.6.2.

⁸⁰ AER, *Draft decision on ActewAGL's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Ausgrid's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014; AER, *Draft decision on Essential Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014.

⁸¹ AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–59.

⁸² AER, *Draft decision on Endeavour Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–59.

⁸³ SA Power Networks, *AER SAPN 022*, 16 February 2015.

⁸⁴ SA Power Networks, *AER SAPN 022*, 16 February 2015.

Other planned replacements

We do not accept any of the forecast volumes in a third category of replacements SA Power Networks proposed, called 'other planned replacements'. Table 16.11 provides a description of the 'other planned replacements' proposed by SA Power Networks.

Table 16.11 Proposed other planned replacements and our assessment

Other planned replacements	Description
Defective single and three phase meters	Defective single and three phase meters that are failing at rate SA Power Networks considers high.
Meters with '4 dials'	Meters which only have 4 dials and therefore cannot record energy consumption greater than 9,999 units.
Meters with no replacement parts	Older meters with no available replacement parts to perform maintenance.
Type 5 CT meters of an advanced age	Older meters SA Power Networks considers likely to fail on the basis of age.

Source: AER analysis; SA Power Networks, AER SAPN 022, 16 February 2015.

We consider planned replacements should only occur when a distribution business is under a regulatory obligation to perform them. Since none of the replacements in the 'other planned' category are driven by a regulatory obligation, we do not consider it prudent or efficient for them to occur.

SA Power Networks provided business cases for the four classes of replacement in the 'other planned' category.⁸⁵ The analysis in all of them was essentially the same. They considered two options for replacing meters. These options were replacement in response to functionality failures as and when they happen (reactive replacement) or conduct a planned replacement of the entire population (proactive replacement).

We do not consider proactive replacement of the 'other planned' category to be a prudent and efficient option. The NER and Australian Standard 1284.13 provide a rigorous regime for determining when proactive replacements should occur. We consider the performance of proactive replacements where that regime does not require them would circumvent SA Power Networks' regulatory obligations and, in effect, impose a higher standard on the business, than it is required to meet. Ultimately this would lead to the incurrence of expenditure in excess of what is prudent and efficient. Hence we do not accept the proactive replacements of any meters in SA Power Networks' 'other planned' category.

⁸⁵ SA Power Networks, AER SAPN 022, 5 March 2015.

Notwithstanding, we accept that these meters are failing, or otherwise require replacement. While we do not consider the proactive replacement of them to be prudent and efficient, individual meters should be replaced when they cease to function. That is, we consider reactive replacement to be a prudent and efficient response, where a distribution business is not under a regulatory obligation to engage in the proactive replacement of a meter population.

We have already provided SA Power Networks with an allowance for reactive replacements. Our preliminary decision is that this allowance will provide the distribution business with an opportunity to recover at least its efficient costs. This is with respect to all of SA Power Networks' reactive replacements, including those in the 'other planned' category. If we were to approve any further reactive replacements, SA Power Networks would likely over recover its costs.

IT expenditure

SA Power Networks proposed \$2.5 million (\$2014–15) for IT infrastructure.⁸⁶ This relates to the costs of acquiring hand held meter reading devices⁸⁷, needed to support their meter and tariff program based on the provision of a 'smart ready' meter.⁸⁸ For the reasons set out in section 16.1.5.2.3.1 we have not approved the smart ready program. It therefore follows that the additional IT infrastructure costs to support this program are also not prudent.

16.1.5.2.4 Forecast operating expenditure

We substitute \$34.9 million in operating expenditure for annual metering services in place of SA Power Networks' proposed \$85.6 million (\$2014–15). This is 41 per cent of the total proposed operating expenditure. Our alternative forecast is in line with SA Power Networks' historic operating expenditure.

The difference between SA Power Networks' proposal and our preliminary decision is because we do not accept SA Power Networks' large step change (\$25.5 million) relating to moving to monthly meter reading. We have also placed greater reliance on historical costs, when conducting our 'base' expenditure analysis. We consider this to be reasonable, since in providing metering services SA Power Networks should, at the very least, be as efficient as it has been in the past. For that reason, we consider our substitute operating expenditure to better reflect SA Power Networks' likely future requirements.

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

⁸⁶ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.4 ACS metering pricing model*.

⁸⁷ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.4 ACS metering pricing model*.

⁸⁸ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 33.

16.1.5.2.4.1 Base

The initial step in our assessment of SA Power Networks' proposed operating expenditure was to consider its 'base' level of expenditure. We looked at what SA Power Networks' base should be, from two different perspectives. These were SA Power Networks' historical operating expenditure and its performance against benchmarking. By contrast, SA Power Networks developed its base using a bottom-up approach only.⁸⁹

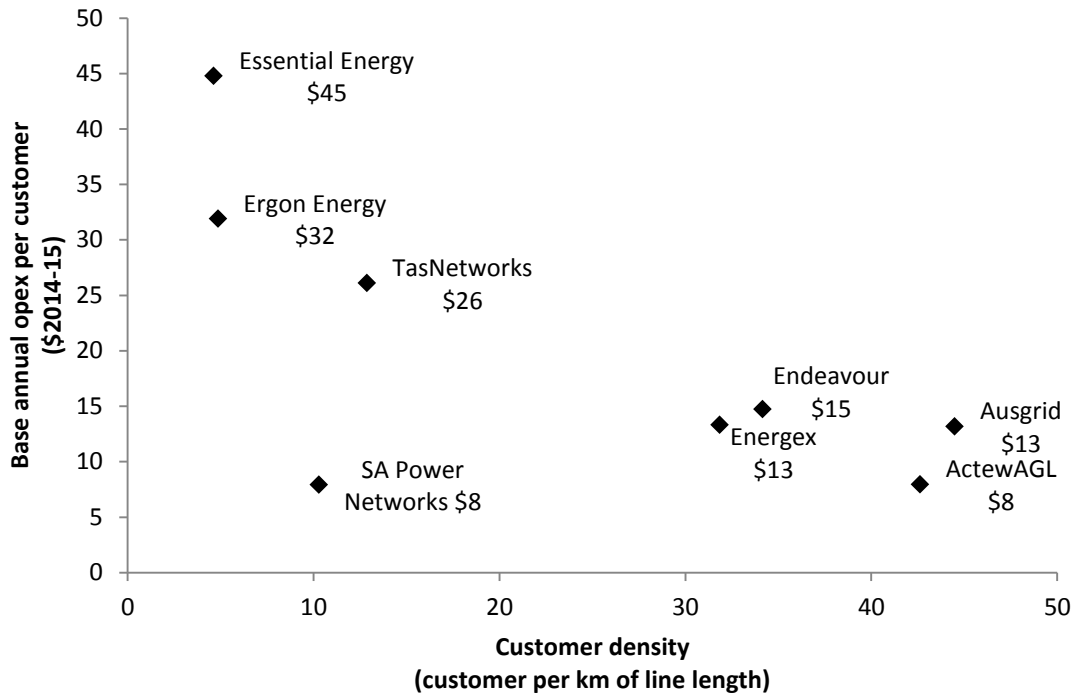
With assessing historical expenditure, we consider SA Power Networks base should be at least as efficient as its costs in previous years. We observed SA Power Networks' historic operating expenditure over a five year period. Applying this approach, we observed a base expenditure of \$8 per customer per year (\$2014–15).

Consistent with our approach for standard control services, we further examined the proposed base by applying benchmarking. To do this we used a partial performance indicator which compared SA Power Networks proposed operating expenditure per customer against other non-Victorian distribution businesses in the national electricity market.

When comparing SA Power Networks proposed operating expenditure to its peers, we normalised our results by accounting for customer density. We calculated this as the number of customers a distribution business has per kilometre of line length. We took customer density into account because, all things equal, businesses with a low customer density are likely to require higher operating expenditures. For example, this could be because of longer travel times to service customers. Figure 16.3 shows the results of our benchmarking.

⁸⁹ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.3 ACS metering tariff development methodology*, October 2014, p. 9–11.

Figure 16.3 Benchmarking of annual metering operating expenditure per customer (\$ 2014–15)



Source: AER analysis

We observe a strong correlation between customer density and costs, and so we can reasonably expect SA Power Networks to require no more opex per customer than a distribution business with a similarly dense network. Taking this approach, we consider TasNetworks to be a relevant comparator for SA Power Networks. This is because the two distributors have similar customer density.

However, our benchmarking results show that SA Power Networks historical opex is relatively efficient compared to TasNetworks, which has similar customer density.⁹⁰ As a consequence, we have decided not make an efficiency related adjustment to the former's base opex.

We have therefore accepted SA Power Networks historical operating expenditure of \$8 per customer/year as the base for setting forecast opex in the 2015-20 regulatory control period.

⁹⁰ This not to say that SA Power Networks is as efficient as it could be; benchmarking only shows the relative efficiency across firms.

16.1.5.2.4.2 Step changes

Our preliminary decision does not apply any step changes to SA Power Networks' base level of operating expenditure.

Reclassification of type 5 meter maintenance costs

We accept that SA Power Networks should be allowed to recover type 5 meter maintenance costs through the annual metering charge in the 2015-20 regulatory control period. These costs were previously recovered through negotiated distribution service charges for type 5 meters.

However, as we discussed in our assessment approach to base opex, we adjusted the base to include type 5 metering maintenance so that the benchmarking analysis was done on a like for like basis (all opex relating to type 5 and 6 metering services). This involved adding historic type 5 metering maintenance costs⁹¹ to SA Power Networks' base opex.

Monthly meter reads

SA Power Networks proposed a step change in its forecast unit costs for meter reading.⁹² This proposed step change applied from 2017–18 onwards. In percentage terms, the step change is equal to about a 280 percent increase in meter reading costs. SA Power Networks stated that it requires the additional expenditure so that it can change to monthly, as opposed to quarterly, meter reading.⁹³

SA Power Networks references customer surveys and SACOSS as supporting the move to monthly meter reads.⁹⁴

However, in their submission, while SACOSS reaffirm their in principle support for moving to monthly meter reads, they state they had 'not been consulted on the details of the proposal or the proposed additional cost'.⁹⁵ By their calculation, the move to monthly meter reads results to 'around \$15 per annum for each small customer and, in our view, warrants more scrutiny than simply being presented as one small part of the regulatory proposal'.⁹⁶

Business SA 'question[s] whether there is a need to spend \$8.5 million on manual meter reads to facilitate new demand tariffs. There is no clear case that monthly meter

⁹¹ SA Power Networks, Response to AER Information Request 44 (meter opex part 2), p. 2.

⁹² SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.3 ACS metering tariff development methodology*, October 2014, p. 9.

⁹³ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 29.3 ACS metering tariff development methodology*, October 2014, p. 10.

⁹⁴ SA Power Networks, *Regulatory Proposal 2015-20, Attachment 14.3 Tariff and Metering Business Case*, p. 31.

⁹⁵ SA Council of Social Services (SACOSS) - Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 35.

⁹⁶ SA Council of Social Services (SACOSS) - Submission on SAPN's regulatory proposal 2015-20, 30 Jan 2015, p. 35.

reads are necessary, or for those customers large enough to be on a demand tariff, could not be provided by a competitive meter service provider'.⁹⁷

SA Power Networks considers that monthly meter reads will significantly benefit vulnerable customers who are most susceptible to bill shock associated with quarterly reads.⁹⁸ However, moving to monthly billing is not contingent on monthly reads. For example, retailers such as Origin and AGL offer bill smoothing options based on estimated or average usage that allows customers to pay in weekly, fortnightly or monthly instalments.⁹⁹

We consider the \$25.5 million proposed step change is not prudent or efficient expenditure for what is essentially an interim solution before advanced metering is rolled out (which will deliver real time data).

Our preliminary decision is to not apply a step change for monthly meter reading to our assessment of SA Power Networks base level of operating expenditure. This is consistent with our decision not to allow step changes associated with the roll-out of 'smart-ready' interval meters.

16.1.5.2.4.3 Trend

We trended the base forward for forecast metering customer growth. We have applied zero forecast real price and productivity growth.

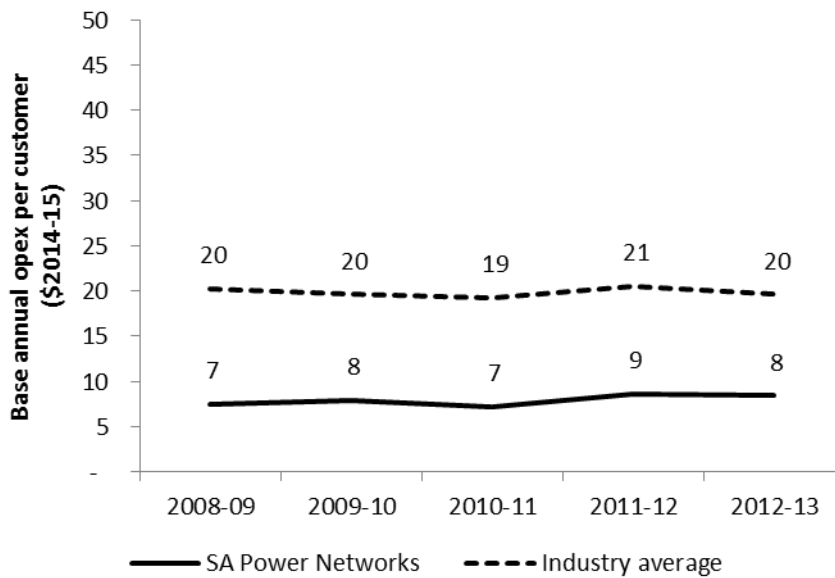
Our analysis for base metering opex used average data from 2008–09 to 2012–13. One would expect to see metering opex per customer increasing over the period if there was real price growth.

⁹⁷ Business SA, Submission on SA Power Networks regulatory proposal 2015–20, January 2015, p. 19.

⁹⁸ SA Power Networks, *Regulatory Proposal 2015-20*, p. 272.

⁹⁹ <http://www.originenergy.com.au/2417/EasiPay-payment-plan>
<http://www.agl.com.au/residential/help-and-support/billing-and-payments/bill-smoothing>

Figure 16.4 Annual default opex per customer



However, Figure 16.4 shows that in the five years to 2012–13, SA Power Networks metering opex per customer was stable. So was the industry average. This implies that either there were no real price increases over this period, or the distributors were able to offset these real price increases with productivity improvements.

Given that opex is largely recurrent and metering opex per customer did not increase over the 2008–09 to 2012–13 period, we do not forecast metering opex per customer to increase in the 2015–20 regulatory control period. Therefore, we have applied zero real price and productivity growth.

This arrives at an alternative operating expenditure forecast of \$34.9 million (\$2014–15).

16.1.5.3 Upfront capital charges

We accept most, but not all, of SA Power Networks' proposed price caps for one-off charges. These charges are made up of material and non-material unit costs. But because they are recovered directly and upfront from a customer, they do not have a forecast volume component; unlike annual metering charges.

We applied the same approach as for annual metering charges, when assessing the material and non-material unit costs for one-off charges. We decided that:

- the proposed material unit costs of some meters were above our consultant's market rates and therefore they were substituted for lower amounts
- the proposed non-material unit costs are reasonable and should be accepted.
- We also accept that customers should have the option to take up a type 5 meter installation when they seek a new or upgraded connection from SA Power

Networks. We therefore considered whether SA Power Networks proposed material costs for type 5 meters fit within Marsden Jacob's observed market ranges. We found that they did and hence they have been approved.

Additionally, we have determined that the upfront capital charge should be annually adjusted for labour price changes. In coming to this conclusion, we note that our preliminary decision has determined that ancillary service fees will be subject to such annual adjustments. The upfront capital charge recovers similar costs to ancillary services fees. It follows that labour price changes should be accounted for in our price control for the upfront capital charge. We have done this in our control mechanism decision in section 16.1.1.5 above.

Not all of the costs associated with the upfront capital charge relate to labour. To take this into account, when making our price control decision we have used a weighted X-factor. Specifically, we observed that about 60 percent of the costs relating to the upfront capital charge are attributable to labour. In setting the X-factor, we therefore applied a weighting of 60 percent to the labour price changes, which we have forecast in this preliminary decision.¹⁰⁰

Our preliminary decision one-off metering charges are set out in Appendix A. Our analysis of SA Power Networks' proposed material unit costs are set out in a confidential appendix.

16.1.5.4 Metering exit fees

Our preliminary decision to continue charging switched customer for the capital component of the annual metering charge. Therefore, there is no risk of stranded assets that need to be recovered through an exit fee.

We do not approve SA Power Networks' proposal to recover administration costs relating to customers transferring to alternative metering providers through an exit fee. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

In assessing all distributors' proposed meter transfer fees, our main focus is on the types of activities that are undertaken by retailers, distributors and metering providers in the National Electricity Market when a customer churns from a distributor owned meter. We also looked at the methodologies distributors adopted to establish the fee. Furthermore, because there is an alternative provider to that of the distributor, those providers' approach to dealing with customer meter churn and any associated costs should provide a direct comparator for that of the monopoly business.¹⁰¹

¹⁰⁰ See attachment 2 of this final decision for more information on how changes in labour costs were forecast.

¹⁰¹ Retailers in the National Electricity Market can and do provide metering services to the contestable elements of the market, namely the medium and large businesses. Distributors at this stage maintain a monopoly provision to household customers but this will change with advent of the AEMC competition in metering rule change.

Retailers submitted that any activities undertaken by the distributors was no different from existing data entry/system management functions undertaken as part of normal business practice and that any incremental costs associated with 'administration' would be absorbed by the entity acquiring the metering customer.¹⁰²

Oakley Greenwood, in its report to Origin Energy corroborated stakeholders views by contending that changing information in the distributors systems, is likely limited to a change in information about the entity that is responsible for the meter; the identity of the metering coordinator; and sufficient information about meter type to enable its verification for tariff assignment, was probably all that was required.¹⁰³

We tested this with retailers, many of whom are already providing metering services to large customers, which is a contestable market. Simply Energy did not agree with the imposition of administration fees; nor did Origin Energy. The latter was concerned that all three NSW distributors used vastly different inputs and therefore required testing against efficient benchmarks before a reasonable costs could be determined.¹⁰⁴ The retailer considered that a consistent approach to the calculation of administrative costs was most appropriate.¹⁰⁵

Simply Energy observed their current role in churning meters (type 4) in the competitively provided commercial market involved administrative transaction costs that were immaterial to it. They also advised that distributors were not currently charging them a meter transfer fee where the customer switched from the distributor to the retailer as metering provider.¹⁰⁶

Commenting on the New South Wales distributors proposals, Simply Energy stated that there appeared no assumption of batch processing. Instead, the proposed charges assumed each meter was being processed individually. Simply Energy noted that if put in the position of the distributors, it would review processes in detail to determine the optimum batch size, which would be at least 20 meters (i.e. customers) per batch.¹⁰⁷ In such circumstances, multiplying Endeavour Energy's proposed five minutes per meter by 20 minutes equates to 100 minutes per batch for each manual process. Simply

¹⁰² Vector Limited, submission on the AER's draft decision on New South Wales and ACT Electricity Distributors' Regulatory Proposals for 2015–16 to 2019–20, pp. 5, 6-8, 13 February 2015, p.p. 6-7; AGL, Alternative approach to the recovery of the residual metering capital costs through an alternative control service annual charge, 27 March 2015, p.2; AGL, email to AER staff, AGL Presentation to AER staff—metering regulation & transition to competition, 13 March 2015.

¹⁰³ Oakley Greenwood, Review of NSW DBs Regulatory Submission, 8 August 2014, p. 7 in Origin Energy, Submission to NSW Electricity distributors' regulatory proposals, 8 August 2014, (attachment 2).

¹⁰⁴ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 1)p. 36.

¹⁰⁵ Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 2), p. 7.

¹⁰⁶ Meeting between respective staff of Simply Energy and AER on 16 March 2015.

¹⁰⁷ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

Energy proposed that 10 minutes was a more credible time.¹⁰⁸ This was also appropriate for other distributors.

Furthermore, Simply Energy advised that the reasonable activities it would have to incur to process a batch of 20 meters and the time taken for each were:

- Meter provider database update—10 minutes
- Banner system meter update—25 minutes
- Metering business system update—25 minutes
- Banner system final read update—10 minutes.¹⁰⁹

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

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

This is confirmed by the Australian Energy Market Operator who has a new set of meter churn procedures due to commence September 2015.¹¹⁰ This new procedure simplifies the meter churn procedure and places the onus on the Financial Responsible Market Participant (as the incoming Responsible Person) and their Metering Provider to update Market Settlement and Transfer Solutions and administer the transfer. The distributor's role is minimised, especially for the displacement of Type 6 legacy meters. Type 5 meters will require a final read. It could be expected that competing meter providers will be sufficiently encouraged to work with distributors to provide them with the necessary final read data. This is because to do otherwise will reduce their profit margins and potentially put them at risk of failing to meet their obligations to provide

¹⁰⁸ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

¹⁰⁹ Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

¹¹⁰ See <http://www.aemo.com.au/Consultations/National-Electricity-Market/Second-Stage-Notice-of-Consultation--Meter-Churn-Package>, accessed 26 March 2015 and <http://www.aemo.com.au/Consultations/National-Electricity-Market/~media/Files/Other/consultations/gas/Churn%20Package%202014/Meter%20Churn%20Procedure%20FRMP%20v10%20clean.ashx> accessed 26 March 2015.

relevant data to ensure market settlement in a timely manner.¹¹¹ It is reasonable to assume that the new meter churn procedures will carry forward into the residential metering market, the competitive metering element of which is now in its infancy.

As a metering provider with experience in competitive metering markets, Vector commented on Endeavour Energy's cost assumptions in its revised revenue proposal. These are reproduced in Table 16.12 where both organisations responses can be compared.

Table 16.12 Endeavour Energy meter transfer fee build up and Vector response

Endeavour Energy Task	Endeavour Energy Time	Vector Comment
Administration Officer updates the meter removal in the Meter Provider Database.	5 min	Valid distributor activity that is currently carried out regularly now. Could not be delivered by Metering Service Provider but could be automated via distributor integration to market systems
Network Billing Data Analyst updates the meter removal and the new metering details (for the non-Endeavour Energy asset) in the Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Network Billing Data Analyst updates the new metering details in the Metering Business System (MBS), which will allow network billing activities to occur.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Metering Officer obtains the final read for the meter and inputs the details of the final read into Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly
The ASP returns the Endeavour Energy removed asset back to the designated Endeavour Energy depot. Endeavour Energy process dictates that the meter is double bagged and goose necked to ensure safe transportation of asbestos contaminated materials. The consumables required to meet these requirements are supplied by Endeavour Energy.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.
Cost of meter disposal.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.

Source: Endeavour Energy; Vector Limited.

¹¹¹ We are aware of instances where some distributors are alleged to have deliberately stalled or frustrated attempts by large commercial users to switch meter provider. However, this is a separate issue of specific business conduct, rather than of efficient billing systems per se.

Vector advised that their response to the activities listed in Table 16.12 was that the tasks were not unique to distributors. Alternative meter service providers can now, and will in the future, undertake many of these tasks. Furthermore, they noted that Endeavour Energy could integrate these activities and tasks with electronic transactions that they presently receive from AEMO.¹¹² Vector says this is how it operates in the market today and did not see why distributors should not do the same. Given that distributors were performing these functions now as standard business practice, Vector could not anticipate what incremental costs would arise as a result of competitive metering.¹¹³

We do not agree with the distributors' position that that an increase in staff will be required within the regulatory periods commencing 1 July 2015. We also find that it will be the meter service provider, as the financially responsible market participant, who will bear the additional costs associated with meter churn, not the distributors.

We find that customers would not be paying an efficient level of costs for meter churn if the distributors proposed transfer fees were approved. A meter transfer fee of the order proposed by SA Power Networks (\$69.50) could amount to a de-facto exit fee that would act as a barrier to competition and the uptake of new advanced meters. While the national electricity law requires us to ensure distributors have the opportunity to recover at least their efficient costs we are not persuaded by the evidence that distributors have material incremental costs to recover in amending records to take account of customer churn. Any incremental costs will be borne by the acquirer of the new meter customer—at the moment, retailers. Furthermore it is noteworthy that distributors are churning type 6 meters for interval meters for customers installing Solar Photovoltaic systems in large numbers without imposing any administrative fees for the meter transfer.

Further support to our findings that the proposed transfer fees are disproportionate to the activities to be undertaken is in comparing the per customer meter opex fee which we have approved in this decision. Our preliminary decision will see SA Power Networks recover \$8 annually for metering opex per customer for meter data services, truck rolls, reading and processing, a share of information technology costs and including overheads. It does not follow that a proposed transfer fee greater than this is reasonable.¹¹⁴

We also do not accept that SA Power Networks recover associated tax and other fixed operating expenditure (such as corporate overheads, contracted IT and meter data management costs) through an exit fee. No other distributor has proposed an exit fee based on such costs. SA Power Networks has no unique obligations, so we see no reason to depart from our approach that is consistent across all the NSW, ACT and QLD distributors.

¹¹² Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

¹¹³ Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015

¹¹⁴ This logic also applies if we take the SA Power Networks' proposed average metering opex per customer per year of \$20.

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

16.1.5.5 Control mechanism

Our preliminary decision applies the control mechanism which we proposed in our final Framework and Approach for SA Power Networks.¹¹⁵

The approved control mechanism includes an 'A-Factor'. In our final Framework and Approach we stated that A-Factor could be used to adjust for 'residual charges when customers choose to replace assets before the end of their economic life'.¹¹⁶ Our preliminary decision, however, establishes a metering tariff structure which does not include such residual charges. Consequently, the A-factor component of the price control we have specified as applying to SA Power Network has been set to zero. See section 16.1.1.5 for further details.

¹¹⁵ AER, Final Framework and Approach for SA Power Networks, April 2014, p. 75.

¹¹⁶ AER, Final Framework and Approach for SA Power Networks, April 2014, p. 76.

A Approved charges

A.1 Metering

Table 16.13 Annual metering charge – Preliminary decision (\$ nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19	2019/20
Type 1–4 'Exceptional' remotely read interval meter	Non-capital	135.07	138.51	142.05	145.67	149.38
	Capital	176.18	180.67	185.28	190.00	194.84
Type 5–6 CT connected manually read meter	Non-capital	73.52	75.40	77.32	79.29	81.32
	Capital	95.90	98.35	100.85	103.42	106.06
Type 5–6 WC manually read meter	Non-capital	8.98	9.21	9.44	9.68	9.93
	Capital	11.71	12.01	12.32	12.63	12.95

Table 16.14 AER preliminary decision X factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	0	0	0	0

Table 16.15 Upfront capital charges – Preliminary decision

Meter	Upfront charge (\$ Dec 2014)
Type 5	
Single element	160.80
Two element	230.54
Three phase	396.43
Type 6	
Single element	100.06
Two element	254.50
Three phase	298.40

Table 16.16 AER preliminary decision X factors for upfront capital charge (per cent)

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