



Issues paper

**SA Power Networks electricity distribution
regulatory proposal**

2015–16 to 2019–20

December 2014

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AER reference: 51225 D14/156464

Request for submissions

Interested parties are invited to make written submissions regarding the distributors' regulatory proposals to us, the Australian Energy Regulator (AER), by the close of business, **30 January 2015**.

We prefer that all submissions sent in an electronic format are in Microsoft Word or other text readable document form. Submissions should be sent electronically to:

- SAElectricity2015@acc.gov.au

Alternatively, submissions can be sent to:

Mr Sebastian Roberts
General Manager
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We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website at www.aer.gov.au. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy, October 2008 available on our website.

Enquires about this paper, or about lodging submissions, should be directed to our Network Opex and Coordination branch on (07) 3835 4669.

Next steps

We will consider and respond to submissions on this issues paper in the context of our regulatory determinations. We expect to publish our preliminary decision in April 2015.

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Shortened forms

Shortened form	Extended form
ACCC	Australian Competition & Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP	consumer challenge panel
CPI	consumer price index
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
NEL	National Electricity Law
NEM	National Electricity Market
NEO	national electricity objective
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RIN	regulatory information notice
WACC, rate of return	weighted average cost of capital

The key terms and their shortened forms, listed above, are largely derived from the National Electricity Rules (the rules). The shortened forms used here are commonly used by us, industry participants and other stakeholders.

1 Introduction

SA Power Networks is a distribution network service provider that supplies electricity to almost all residences and businesses in South Australia. It has submitted to us for assessment its regulatory proposal. This sets out the revenue it proposes to collect from electricity consumers through distribution charges for the next five year period (2015–20).

Distribution charges make up about 30 per cent of a typical residential customer's bill.¹ Other components include the cost of generation, transmission network charges and retailer costs. We, the Australian Energy Regulator (AER), approve the revenues that a distribution company is allowed to recover from consumers. We will assess the proposal submitted to us by SA Power Networks. In doing so, we will work within the regulatory framework we administer. That is, we will apply the National Electricity Law (NEL) and National Electricity Rules (rules), as we are required to do. Both put the focus squarely on outcomes for electricity consumers.

Under the NEL and the rules, we must decide whether SA Power Networks proposal represents its efficient costs. If so, we will accept it. If not, we will determine ourselves what revenues SA Power Networks will be allowed to earn over the 2015–20 period.

Whether or not SA Power Networks' proposal should be accepted or revised is our responsibility. However, we are keen to hear the views of electricity consumers and other stakeholders as these views will form a critical part of our assessment. This issues paper is the first step in our public consultation process. It sets out our initial impressions of SA Power Networks' proposal, including what we think will be some of the key issues for our assessment. We hope this paper is helpful for readers to form their own views on SA Power Networks' proposal.

We will make a preliminary determination by the end April 2015, which will take effect at the commencement of the regulatory control period on 1 July 2015. As required by the transitional arrangements in the rules, we will then revoke the preliminary determination and make our final determination by the end of October 2015. This means that the network prices which take effect on 1 July 2015 will be based on our preliminary determination. Our final determination will take effect on 1 July 2016. Any necessary corrections for the 2015–16 year will be reflected in the revenues we approve for 2016–17 and the remaining years of the regulatory period.

There have been significant changes to the regulatory framework we administer. The Australian Energy Market Commission (AEMC) finalised amendments to the rules in November 2012. These changes resulted in a renewed emphasis on the long term interests of consumers. The appeal process relating to our network determinations was also amended so that any appeals by distributors such as SA Power Networks must demonstrate that the changes sought would leave consumers better off. The revised rules have led us to develop guidelines that set out how we propose to approach important aspects of our review.

SA Power Networks' proposal is available on our website (www.aer.gov.au). The following sections of this paper highlight aspects of SA Power Networks' proposal. This material examines the main components of SA Power Networks' total revenue proposal—capital expenditure (capex), operating expenditure (opex) and the rate of return. Details on when and how to make submissions, along with other key dates in our assessment process, are set out below.

¹ This proportion varies across jurisdictions.

Your submission and key dates

It is important that your submission is, as much as possible, supported by reasons, facts and analysis. General statements made about a regulatory proposal are of limited use for our assessment. If you consider a certain aspect of SA Power Networks' regulatory proposal is not justified, you should state why you consider it is not justified, with reference to reasons that support your views. You should also state what further information you consider SA Power Networks should provide to justify that aspect of its proposal.

When considering the questions on which we would like feedback, it is useful to keep in mind that we must comply with the NEL and rules. The capex and opex forecasts of a distribution business such as SA Power Networks must be aimed at meeting expected demand and all regulatory obligations as well as maintaining the safety of the network. If there are no regulatory obligations in relation to quality, reliability and security of supply, a business is to maintain existing levels. We may also take into account feedback from consumers around their service levels and the network charges they pay.

We are primarily interested in receiving submissions on SA Power Networks' proposed approaches to opex, capex, the rate of return and consumer engagement. However, we will consider submissions on any aspect of SA Power Networks' proposal. Key dates for our assessment process are set out in Table 1 below.

Table 1 Key dates for SA Power Networks distribution determination process

Task	Date
Distributor regulatory proposal submitted to AER	31 October 2014
Publish regulatory proposal and supporting documents	19 November 2014
AER public forum	10 December 2014
Stakeholder submissions on regulatory proposal close	30 January 2015
AER issues preliminary decision	30 April 2015
AER preliminary decision conference	May 2015*
Stakeholder submissions on preliminary decision close	2 July 2015
Distributor submits revised regulatory proposal	2 July 2015
Stakeholder submissions on revised regulatory proposal close	24 July 2015
AER revoked preliminary decision and issues final decision	31 October 2015

*Note: Dates are indicative only and will be confirmed as process progresses.

2 Our initial observations

SA Power Networks has proposed average annual network price increases of around 2 per cent over the 2015–20 period.²

We will assess the proposal from SA Power Networks to determine whether we can accept it. We will form a view on whether it reflects the circumstances SA Power Networks will be operating in. The circumstances have changed since we made SA Power Networks' last determination five years ago, including:

- the cost of infrastructure financing has fallen substantially
- demand for electricity has been flat or declining.

The main components of SA Power Networks proposed revenue are the rate of return required to finance its assets, its capex and its opex.

SA Power Networks' has proposed a lower rate of return on its assets than in the 2010–15 period when it received 9.76 per cent. It has proposed a rate of return of 7.62 per cent.

SA Power Networks has proposed to increase its capex by over 50 per cent compared to its actual capex in the 2010–15 period and its opex by around 33 per cent.

Looking at the components of its capex proposal, SA Power Networks has proposed to increase its network augmentation spending by around 49 per cent and its asset replacement spending by around 94 per cent. We will investigate SA Power Networks' rationale for its proposed increased capex. In doing so, the questions we need to ask are:

- What is driving the scope, scale and timing of SA Power Networks' proposed capex over the 2015–20 period? For example, are there regulatory, legislative or other obligations that require the proposed higher levels of expenditure?
- Whether stakeholders consider SA Power Networks' proposal is in the long term interests of electricity consumers in South Australia?

We will consider whether the opex proposal submitted by SA Power Networks reasonably represents the efficient cost of operating its network. We will assess its opex proposal against the opex criteria set out in the rules.³

We also observe SA Power Networks has departed from the Rate of Return Guideline⁴ to develop its proposed rate of return on its assets. We will consider whether SA Power Networks' proposed rate of return achieves the rate of return objective, that it reflect the efficient financing costs of a benchmark efficient entity with similar risk.⁵

We recognise some other factors are putting upwards pressure on prices. These include that SA Power Networks' asset base is larger than it was five years ago. These assets will require financing in the years to come.

² In \$nominal terms.

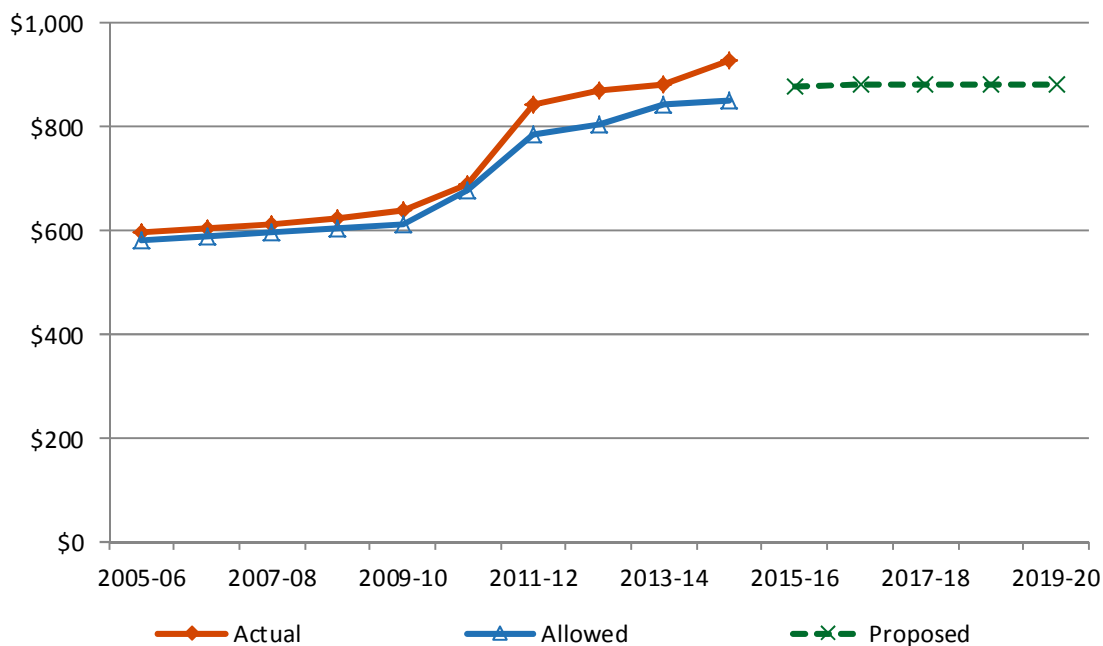
³ NER, cl. 6.5.6(c).

⁴ AER, *Rate of return guideline*, December 2013.

⁵ NER, cl. 6.5.2(b).

Figure 1 below shows SA Power Networks' proposed total revenues compared to its revenues in the current and previous periods.

Figure 1 SA Power Networks' proposed total revenue (\$million, 2014–15)⁶



Source: Historical actual revenue is drawn from SA Power Networks' submitted economic benchmarking RINs. The 2014–15 amount is drawn from SA Power Networks' submitted reset RIN. Historical allowed revenue is drawn from our 2005–10 and 2010–15 distribution determinations. SA Power Networks' proposed revenues are drawn from its submitted PTRM.

Our initial impression is that the main drivers of SA Power Networks' revenue proposal are:

- an expanded capex program
- higher opex due to a range of factors that include increasing labour costs, vegetation growth, IT services and increased asset inspections
- a lower rate of return.

⁶ SA Power Networks' operates under a weighted average price cap. This means it is able to maintain average tariffs while varying some components. This potentially allows revenues to be different to the revenues we determine, or allow, in advance. We consider this explains the difference between actual and allowed revenues shown in figure 1.

3 Capital expenditure

The most significant elements of total capex are generally network augmentation expenditure (augex), asset replacement expenditure (repex) and connections. SA Power Networks has proposed to increase its capex by around 50 per cent in the 2015–20 period compared to the 2010–15 period. It has proposed to increase both its asset repex and its augex. It submitted that its asset investment plans are justified by the age of its asset base, increasing asset failures and operational safety concerns including bushfire risk.

Capex refers to the capital expenses incurred in the provision of network services. Capex is added to the regulatory asset base and so forms part of the capital costs of the building blocks used to determine a distributor's total revenue requirement. Under the rules, we must accept a distributor's proposed forecast of total capex if we are satisfied it reasonably reflects the capex criteria.⁷ The capex criteria relate to the efficient costs incurred by a prudent operator in light of realistic demand forecasts. We must have regard to the capex factors in the rules when making that decision.⁸

If we are not satisfied a distributor's capex proposal reasonably reflects the capex criteria, we must not accept the forecast. In that case, we must estimate the total required capex that, in our view, does reasonably reflect the capex criteria taking into account the capex factors. The approach we will adopt to assess the services providers' forecasts of total capex is outlined in our expenditure forecast assessment guideline.⁹

Question

Do you think that SA Power Networks' capital expenditure proposal is adequately justified?

3.1 SA Power Networks' capital expenditure proposal

Table 2 summarises forecast standard control services capex proposed by SA Power Networks.¹⁰ It has proposed capex levels significantly higher than its actual capex for the 2010–15 period.

Table 2 SA Power Networks' capital expenditure proposal

2015–20 total capex proposal (\$million, 2014–15)	Change from 2010–15 total actual capex (per cent)
\$2,528	+ 51.7

Source: Actual total capex is drawn from SA Power Networks' submitted Roll Forward Model (RFM). Proposed capex is drawn from the "assets" sheet of SA Power Networks' submitted Post Tax Revenue Models (PTRM).

Figure 2 below shows SA Power Networks' capex proposal, compared to its 2010–15 actual capex and capex allowance.

⁷ NER, cl. 6.5.7(c).

⁸ NER, cl. 6.5.7(e).

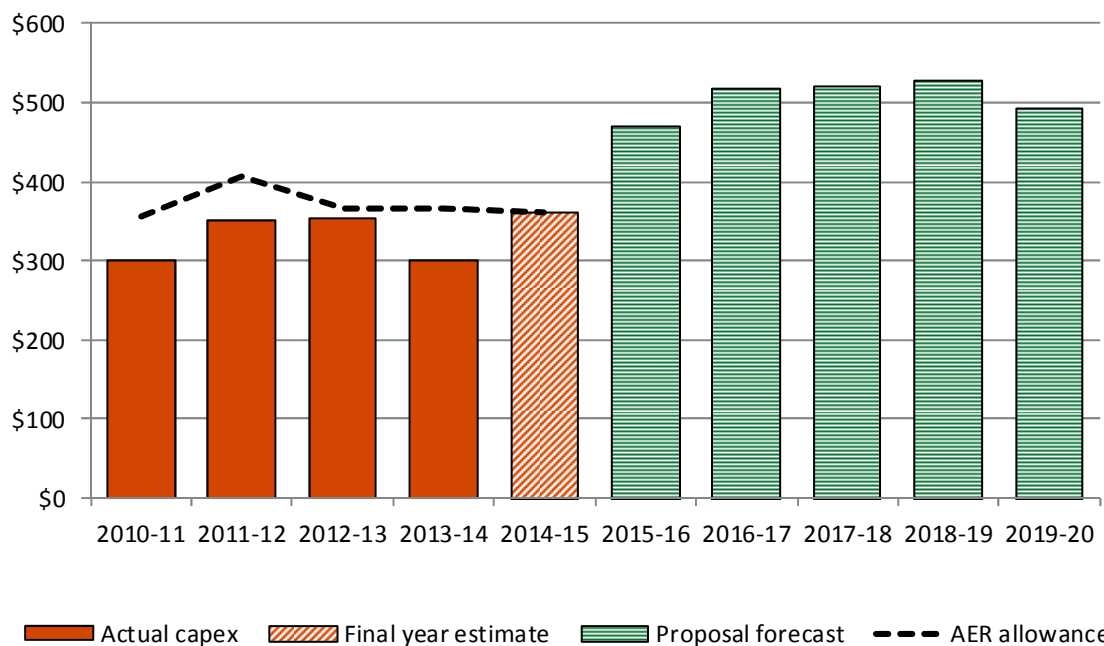
⁹ AER, *Expenditure forecast assessment guideline*, November 2013.

¹⁰ Standard control services include the core activities of planning, constructing and operating a distribution network. It is not practical to separately charge individual consumers for these network services, so the cost of providing standard control services is averaged across all electricity consumers. These averaged costs are recovered from all consumers through distribution network charges.

SA Power Networks underspent its capex allowance in the 2010–15 period. This means that its opening regulatory asset base (RAB) for the 2015–20 period is smaller than anticipated, which means future revenues will not increase as much as had been expected. It also suggests the previous allowance may have been higher than necessary.

We note the scale of SA Power Networks' proposed capex program for the 2015–20 period, representing an increase of more than 50 per cent compared to the current period. At issue is whether this expenditure program is justified given SA Power Networks' forecasts ongoing flat demand.

Figure 2 Capital expenditure (\$million, 2014–15)



Source: AER capex allowance is drawn from the PTRM determined by the AER for the 2010–15 period as varied by the Australian Competition Tribunal (the Tribunal). Actual capex is drawn from SA Power Networks' submitted RFM. Proposed capex is drawn from SA Power Networks' submitted PTRM.

3.2 Key drivers of SA Power Networks' capital expenditure proposal

SA Power Networks submitted that its proposed capex requirements are substantially influenced by the need to maintain high levels of network reliability and to replace defective assets.¹¹

Asset renewal/replacement

SA Power Networks' replacement capital expenditure, or repex, proposal for the 2015–20 period is around double its actual repex in the current period. In support of its capex proposal, SA Power Networks submitted that it currently has the oldest average asset life of all NEM distributors.

SA Power Networks submitted that more frequent asset inspections has identified an increased number of asset defects compared to past experience. It further submitted that an audit of its compliance with its plan for safety, reliability and maintenance found increased repex is required to return its asset related risk levels to acceptable levels. Also, that because its plan has been approved

¹¹ SA Power Networks, *Regulatory proposal*, p. 180.

by the Essential Services Commission of South Australia (ESCOSA), it is obliged to meet the safety risk requirements of that plan.¹²

Table 3 below summarises the total repex proposed by SA Power Networks for the 2015–20 period.

Table 3 SA Power Networks' replacement capital expenditure proposal

2015–20 period (\$million, 2014–15)	Proportion of SA Power Networks' total 2015–20 capex proposal	Change from actual repex in 2010–15 period
\$792.0	31.9 per cent	+ 94 per cent

Source: Repex drawn from table 20.4 of SA Power Networks' Regulatory proposal.

Network augmentation

Network augmentation expenditure, or augex, may be required to extend the network to connect more customers or to strengthen it to cope with additional load. Augex may also enhance network reliability or improve operational safety through installation of new or upgraded assets.

SA Power Networks has also proposed a significant increase in its network augmentation expenditure (augex). Table 4 summarises SA Power Networks' total augex for the 2015–20 period.

Table 4 SA Power Networks' augmentation capital expenditure proposal

2015–20 period (\$million, 2014–15)	Proportion of total 2015–20 capex proposal	Change from actual augex in 2010–15 period
\$884.0	35.6 per cent	+ 49 per cent

Source: Augex drawn from table 20.4 of SA Power Networks' regulatory proposal.

Around one third of SA Power Networks' total proposed augex for the 2015–20 period is comprised of safety related augex. This represents a large increase compared to past experience, both in absolute terms and relative to its other augex and other capex more generally. SA Power Networks has proposed to increase its safety related augex from \$16.9 million (\$nominal) in the 2010–15 period to \$319.5 million (\$nominal) for the 2015–20 period. That is, around 19 times its current levels.

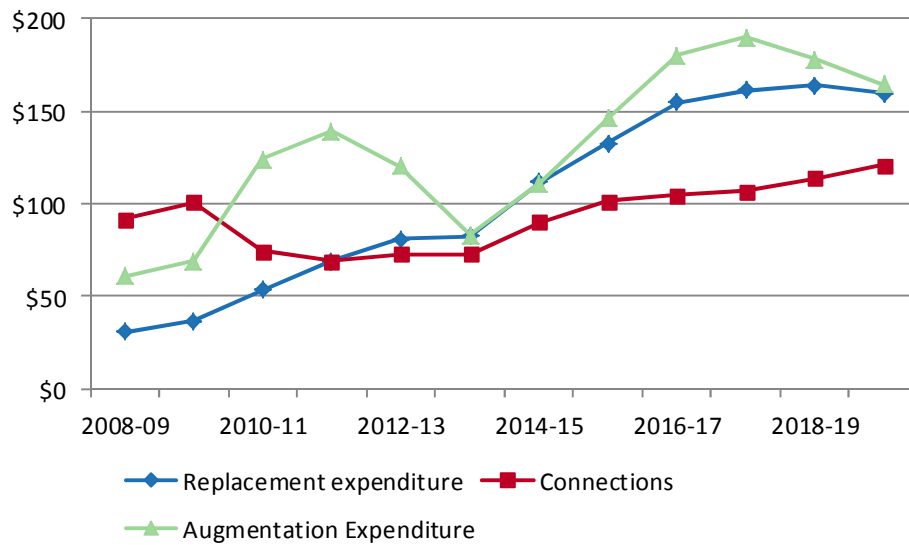
Of its proposed safety related augex, SA Power Networks submitted that \$220 million (\$2014–15) is related to bushfire risk mitigation. This includes proposed works to install upgraded recloser devices and to underground targeted sections of overhead lines. A further \$77.5 million (\$2014–15) is attributed to a road safety program, to underground lines and remove poles at high traffic road intersections.

While we recognise the importance of investing in safety measures, the scale of the proposed safety related augex is notable. We will consider closely SA Power Networks' proposed augex and its rationale for the levels proposed.

Figure 3 below shows SA Power Networks' proposed repex, augex and connections spending for the 2015–20 period compared to the current period. Each of these three types of capex is proposed to increase over the period, though augmentation capex is proposed to decline somewhat over the last two years. Connections spending is proposed to increase, despite SA Power Networks' forecasting flat or declining demand.

¹² SA Power Networks, *Regulatory proposal*, p. 181.

Figure 3 Capital expenditure components (\$million, 2014–15)



Source: Forecasts from SA Power Networks' submitted reset RIN.

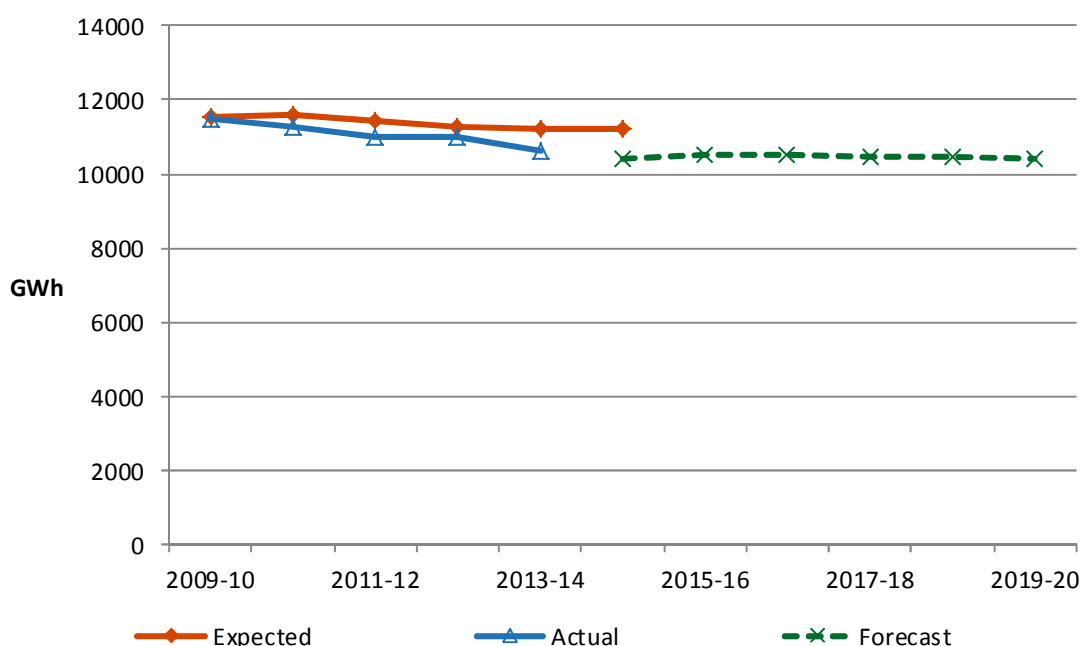
Demand growth

While total demand, or network wide electricity consumption volumes, is an indicator of the overall pressure on SA Power Networks to invest in their capacity, peak demand is a more significant driver of augex requirements. SA Power Networks' forecast for peak demand reflects a continuation of the recent trend of flat or declining peak demand.

SA Power Networks expects peak demand to decline, on average, by 0.2 per cent in each year of the 2015–20 period. SA Power Networks submitted that this peak demand forecast is in part driven by the uptake of small scale distributed solar PV across its network.

SA Power Networks also forecasts flat overall electricity consumption from its network during the 2015–20 period. Figure 4 below shows SA Power Networks' consumption volume forecast, with its expected and actual consumption volumes in the 2010–15 period.

Figure 4 Electricity volumes (consumption)



Source: Historical actual volumes are drawn from SA Power Networks' submitted economic benchmarking RINs. Forecasts are drawn from SA Power Networks' submitted reset RIN.

Demand management

Demand management refers to any strategy to mitigate growth in consumption volumes or peak demand. Demand management can have positive economic impacts by encouraging more efficient use of existing network assets, resulting in lower prices for network users, reduced risk of stranded network assets and benefits for the environment. Demand management is an integral part of good asset management for network businesses.

In some circumstances, demand management can provide efficient alternatives to network investments, by deferring the need for augmentations to relieve network constraints. Costs of network augmentation projects can be significantly greater than the costs of conducting demand management projects to defer an augmentation project. Deferral of network investment may result in efficiency benefits, as the same level of reliability and service is provided by a smaller, better utilised network.

Network owners can undertake demand management through a range of mechanisms. These include incentives for customers to change their demand patterns, operational efficiency programs, load control technologies, or alternative sources of supply (such as distributed or embedded generation and energy storage).

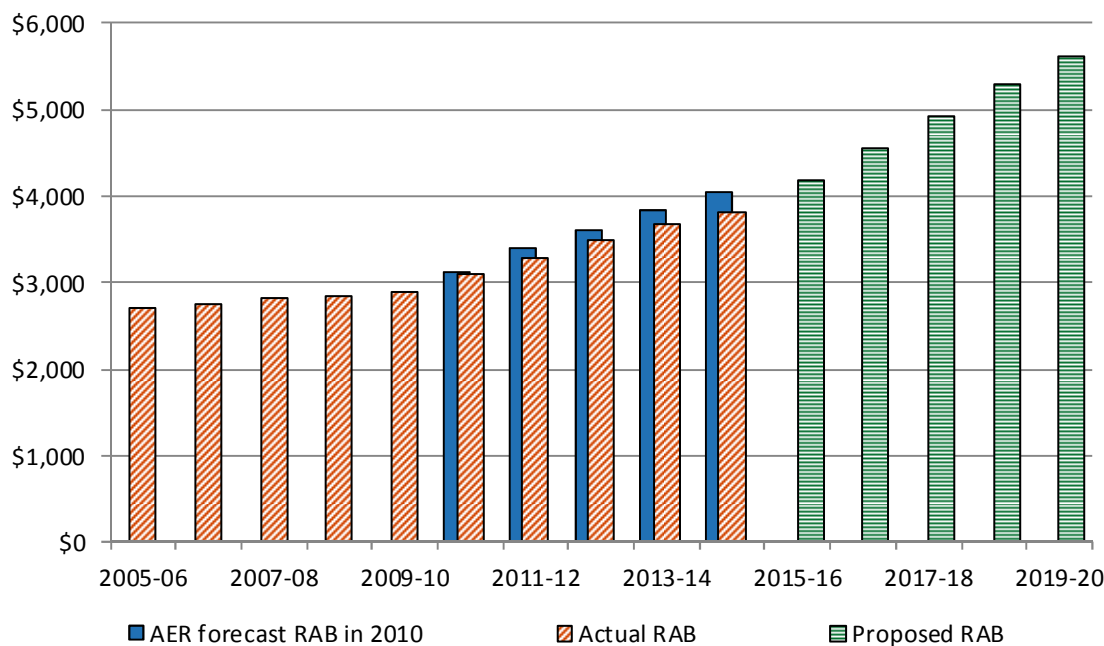
SA Power Networks submitted that its augex forecasts incorporate the impact of non-network alternatives to large augmentation projects, where a preliminary assessment identifies this as cost effective. As an example of its demand management activity, SA Power Networks' regulatory proposal discusses a non-network alternative undertaken at Bordertown, to defer around \$26 million in capital

works for substation upgrades.¹³ However, SA Power Networks also submitted that, based on its assessment, non-network alternatives have limited potential to affect forecast capex levels.¹⁴

3.3 Regulatory asset base proposal

A distributor's regulatory asset base (RAB) is the outcome of its cumulative capex spending. SA Power Networks has proposed to increase its capex spending in the 2015–20 period compared to the 2010–15 period. As a result, SA Power Networks' RAB is proposed to grow over the period. Figure 5 shows SA Power Networks' proposed RAB, compared to its past and current annual RAB.

Figure 5 Regulatory asset base (RAB) values (\$nominal)



Source: Historical actual RAB values are drawn from SA Power Networks' submitted roll forward model (RFM). SA Power Networks' proposed RAB values are drawn from its submitted PTRM.

SA Power Networks proposed to increase the size of its RAB by around 47 per cent over the 5 years of the 2015–20 period. Because electricity network assets have long effective lives, consumers finance the cost of assets added to the RAB over a number of years. We will consider closely the rationale provided by SA Power Networks for its proposed rapid growth in its RAB in the 2015–20 period.

¹³ SA Power Networks, *Regulatory proposal*, p. 255.

¹⁴ SA Power Networks, *Regulatory proposal*, p. 213.

4 Operating expenditure

SA Power Networks has proposed to increase its opex in the 2015–20 period by 33 per cent compared to its actual opex in the 2010–15 period.

Opex refers to the operating, maintenance and other non-capital expenditure incurred in the provision of network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during the 2015–20 period for the efficient operation of its network. It is one of the building blocks used to determine the distributors' total revenue requirement. Under the rules, we must accept a distributor's forecast of total opex if we are satisfied it reasonably reflects the opex criteria.¹⁵ The opex criteria relate to the efficient costs incurred by a prudent operator in light of realistic demand forecasts. We must have regard to the opex factors when making that decision.¹⁶

If we are not satisfied a distributor's opex proposal reasonably reflects the opex criteria, we must not accept it.¹⁷ We must estimate the total required opex that, in our view, reasonably reflects the opex criteria taking into account the opex factors. The approach we will adopt to assess the distributor's forecasts of total opex is outlined in our expenditure forecast assessment guideline.¹⁸

Question

Is SA Power Networks' operating expenditure proposal adequately justified?

4.1 SA Power Networks' operating expenditure proposal

Table 5 summarises forecast standard control services opex proposed by SA Power Networks.

Table 5 SA Power Networks' forecast standard control services opex (\$million, 2014–15)¹⁹

2015–16	2016–17	2017–18	2018–19	2019–20	Total
\$285.7	\$298.9	\$315.9	\$324.5	\$329.1	\$1,554.1

Source: SA Power Networks, *Regulatory proposal*, table 21.1.

Figure 6 below shows SA Power Networks' proposed opex in the 2015–20 period, compared to its allowance and actual opex in the 2010–15 period.

¹⁵ NER, cl. 6.5.6(c).

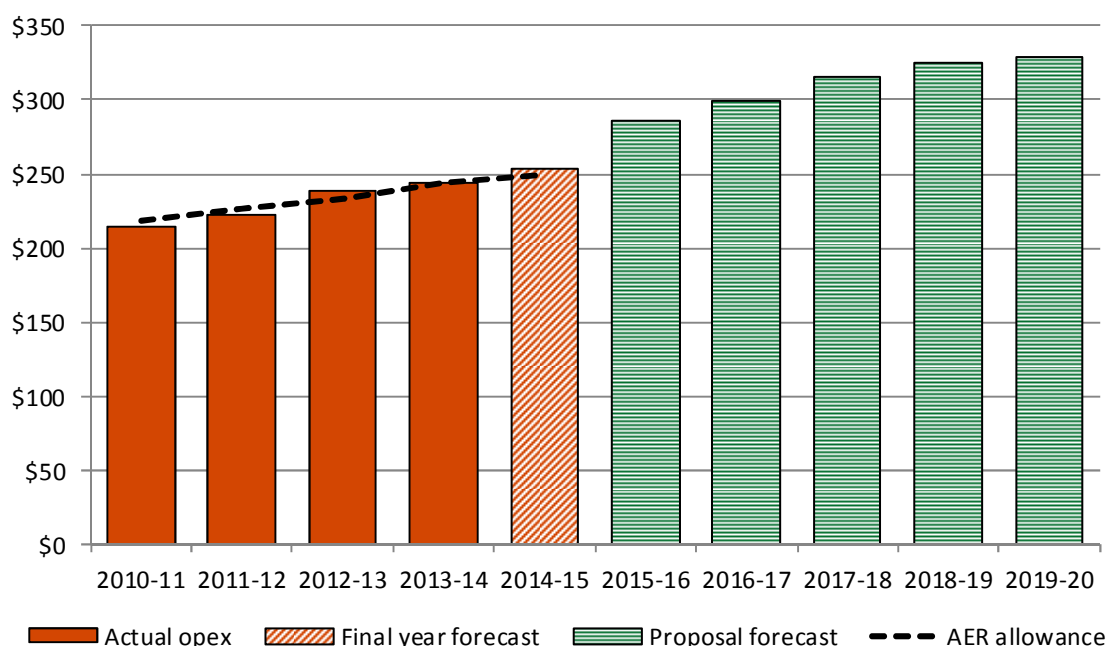
¹⁶ NER, cl. 6.5.6(e).

¹⁷ NER, cl. 6.5.6(d).

¹⁸ AER, *Expenditure forecast assessment guideline*, November 2013.

¹⁹ Opex costs shown exclude the distributors' FIT costs.

Figure 6 Operating expenditure (\$million, 2014–15)



Source: Historical opex amounts are drawn from SA Power Networks' submitted reset regulatory information notice (RIN). Forecast opex amounts are drawn from SA Power Networks' submitted PTRM. The historical opex allowance is drawn from the Tribunal varied PTRM for the 2010–15 period.

4.2 Key drivers of the distributors' operating expenditure proposals

A summary of the main drivers of SA Power Networks' opex forecast is outlined below.

Table 6 SA Power Networks—Drivers of opex forecast

Cost driver	Description of driver
Labour cost escalation	SAPN forecast its opex to increase by \$57.1 million (\$2014–15) due to increases in labour prices.
Output growth	SAPN forecast its opex to increase by \$46.7 million (\$2014–15) due to output growth. To forecast output growth, SAPN has forecast the expected opex impact given the expected growth in the size of its distribution network, workforce size, and customer numbers. ²⁰
IT	SAPN forecast an additional \$43.9 million (\$2014–15) on the maintenance and support of its IT systems. This includes additional costs of \$65.1 million (\$2014–15) offset by productivity improvements of \$21.2 million arising from capital investment in its IT systems. ²¹
Asset inspections	SAPN forecast an additional \$42.1 million on asset inspections. This includes: <ul style="list-style-type: none"> additional opex of \$26.5 million (\$2014–15) to inspect poles previously considered “no

²⁰ SA Power Networks, *Regulatory proposal*, pp. 264–265

²¹ SA Power Networks, *Regulatory proposal*, p. 259.

Cost driver	Description of driver
	<p>access" and to assess the condition of underground cables.</p> <ul style="list-style-type: none"> additional opex of \$15.6 million (\$2014–15) to move to an asset inspection frequency of five years in bushfire risk areas.²²
Demand side participation	<p>From July 2015 SAPN proposes to transition small-market customers to a new cost reflective tariff based on maximum demand. It forecasts additional opex of \$33.8 million (\$2014–15) relating to this tariff. This includes</p> <ul style="list-style-type: none"> support and maintenance of new IT systems to enable the proposed tariff to be implemented, and to process the increased volumes of data from smarter meters customer and retailer engagement to support customers through the transition to its network tariff additional opex on telecommunications for a subset of the meters it installs.²³
Vegetation management	<p>SAPN forecast an additional \$31.9 million (\$2014–15) on vegetation management. This includes:</p> <ul style="list-style-type: none"> an additional \$15.3 million (\$2014–15) to remove inappropriate, fast growing or large trees. an additional \$13.5 million (\$2014–15) to implement a more frequent cutting cycle in Adelaide and regional townships.²⁴
Telecommunications	<p>SAPN forecast an additional \$16.6 million (\$2014–15) relating to telecommunications. This includes:</p> <ul style="list-style-type: none"> an additional \$7.9 million in maintaining a new mobile radio network an additional \$5.7 million associated with managing additional workload associated with its Telecommunications Network Operations Centre.²⁵
Workplace health and safety	<p>SAPN forecasts additional opex of \$12.9 million on initiatives designed to meet its requirements under the Workplace Health and Safety Act and Regulations (2012).²⁶</p>

4.3 Step changes

SA Power Networks has proposed step changes. Under the guideline forecasting approach, step changes allow for adjustments to forecast opex to account for changed circumstances in the forecast period that have not been addressed by base opex or the rate of change.²⁷ We may include step changes for changes to ongoing costs associated with new regulatory obligations and for efficient capex/opex trade-offs.²⁸ Step changes may be positive or negative. We may consider other components of the service providers' opex forecasts as step changes within the guideline forecasting

²² SA Power Networks, *Regulatory proposal*, p. 257.

²³ SA Power Networks, Attachment 21.13 Step changes, 30 October 2014, pp. 73-79.

²⁴ SA Power Networks, *Regulatory proposal*, p. 260.

²⁵ SA Power Networks, *Regulatory proposal*, p. 259.

²⁶ SA Power Networks, *Regulatory proposal*, p. 257

²⁷ AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 24.

²⁸ AER, *Expenditure assessment forecast guideline - Explanatory Statement*, November 2013, p. 51.

approach. We encourage you to review SA Power Networks' submitted step change materials and submit to us your views to inform our assessment.

SA Power Networks has proposed step changes for the following:

- changes in legal and regulatory obligations
- operating costs arising from proposed capital expenditure
- delivering on consumer expectations identified by its consumer engagement program
- financing related matters.

We will assess SA Power Networks' proposed step changes as we consider their overarching opex proposals.

4.4 Forecast efficiency carryover amounts

To encourage a distributor to become more efficient, we typically apply an efficiency benefit sharing scheme (EBSS). In our Final Determination for the 2010–15 period, we determined that version 1 of the distribution EBSS established by the AER in June 2008 would apply to SAPN for the 2010–15 period. This scheme sets out how carryover amounts will be calculated for the purpose of determining EBSS revenue in the 2015–20 period.

The EBSS rewards distributors for efficiency gains achieved during a regulatory control period and penalises them for efficiency losses. The distributors are allowed to retain their efficiency gains for a period of time, but in the longer term their allowances are reduced, meaning lower prices for customers. They will receive any rewards or penalties gained during 2010–15 in the 2015–20 period.

SA Power Networks has included in its revenue proposal carryover amounts that relate to the EBSS that applied during the 2010–15 period. SA Power Networks proposes to carry over \$25.9 million into the 2015–20 period.²⁹

4.5 Opex efficiency

Because opex is largely recurrent in nature, opex forecasts are developed using a base–step–trend approach. Under this approach, opex costs from a chosen base year are used as the starting point to forecast future opex. A key issue for us in assessing a distributor's forecast opex is the efficiency of its base year opex.

Our Expenditure Forecast Assessment Guideline sets out that we are interested in whether base opex is materially inefficient.³⁰ If so, we may adjust the base year opex to account for any apparent level of inefficiency. While we apply a number of techniques to assess the efficiency of base opex, an important assessment technique is benchmarking.

We recently published an annual benchmarking report covering all of the electricity network service providers in the National Electricity Market. We also recently released a draft determination on the NSW/ACT electricity distributors which includes benchmarking techniques specific to opex. The work we undertook for those reports is relevant to the proposal submitted by SA Power Networks. Figures

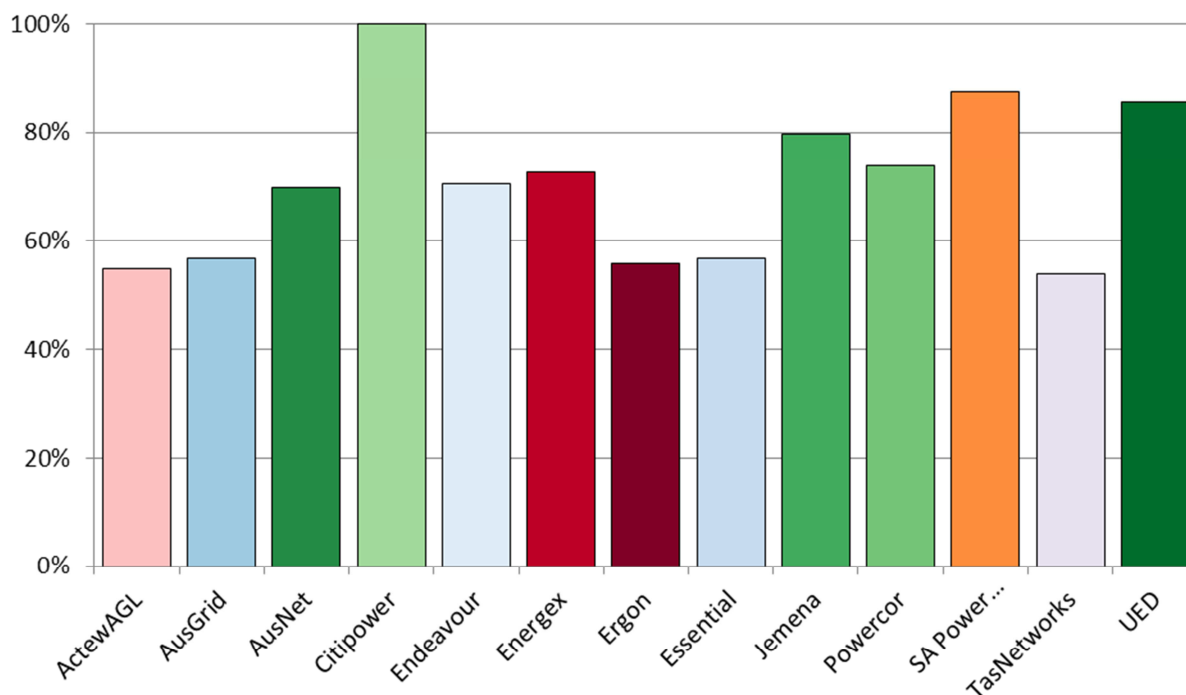
²⁹ SA Power Networks, *Regulatory proposal*, p. 280.

³⁰ AER, *Expenditure Forecast Assessment Guideline*, November 2013.

8 and 9 below show efficiency measures that relate the services delivered by distribution networks to the costs they incur in providing those services.³¹

Figure 8 shows the results of our overall benchmarks for NEM electricity distributors. That is, the relative efficiency of the distributors in terms of their total costs, including opex and capex. A higher percentage equates to a more efficient distributor relative to its peers.

Figure 7 MTFP³² Performance (average 2006–2013)



Source: Economic Insights, 2014.

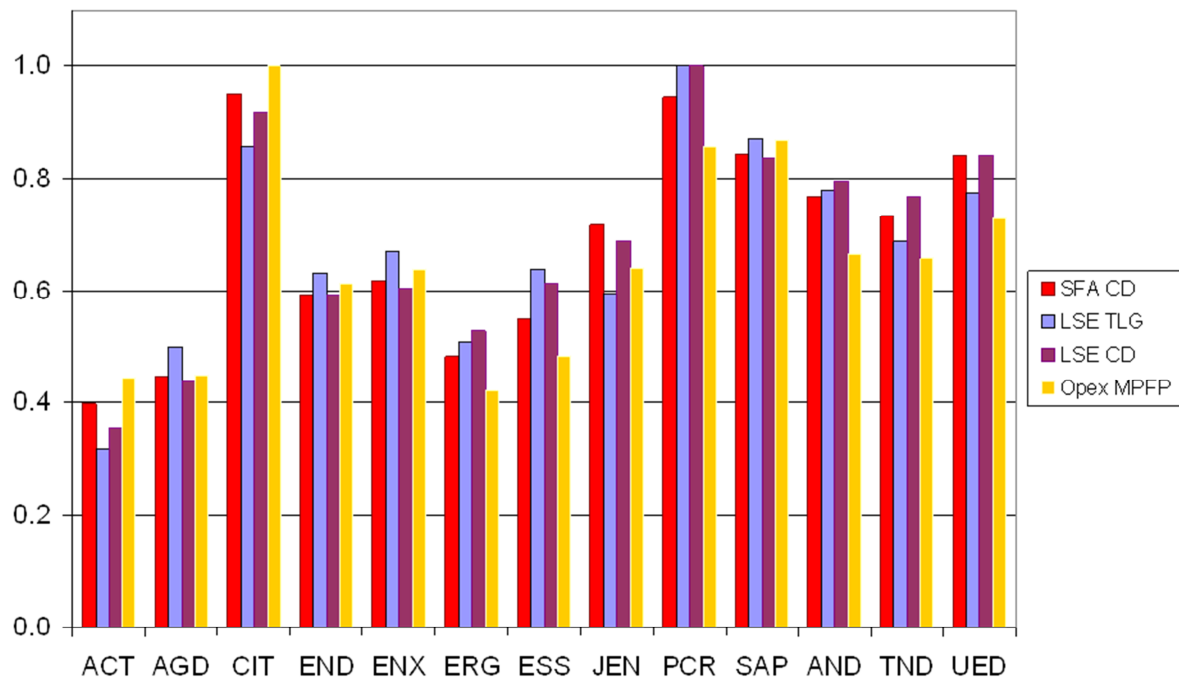
Figure 9 shows our opex specific benchmarks for distribution businesses.³³ Again, a higher index number equates to a more efficient distributor relative to its peers.

³¹ The methodology and assumptions used to calculate the above measures are set out in detail in our annual benchmarking report, and supporting report prepared by Economic Insights. These are available on our website www.aer.gov.au.

³² Multilateral total factor productivity.

³³ The methods include a Cobb Douglas stochastic frontier analysis (SFA CD) opex cost function model, Cobb Douglas and translog least squares econometrics (LSE) opex cost function models and opex multilateral partial factor productivity (MPFP) indexes.

Figure 8 NEM distributors' average opex efficiency scores 2006–2013³⁴



Source: Economic Insights, 2014.

Figures 8 and 9 show:

- SA Power Networks appears to perform relatively well compared to many of its peers, though it may not be as efficient as the most efficient service providers
- there may be scope for SA Power Networks to make efficiency improvements.

The relative efficiency outcomes shown in figures 8 and 9 could be attributable to external factors. We will assess these issues as we consider SA Power Networks' opex proposal and total revenue proposal. We welcome submissions from consumers and other stakeholders on the benchmarking results we have derived and their implications.

³⁴ Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, p. 46.

5 Rate of return

SA Power Networks has proposed a rate of return of 7.62 per cent.³⁵ This proposed rate of return is lower than that received by SA Power Networks in the 2010–15 period (9.76 per cent). As noted previously, SA Power Networks has proposed to depart from the Rate of Return Guideline.³⁶ Through this review we will assess SA Power Networks' reasons for its proposed departures to determine whether they achieve the rate of return objective, that the rate of return reflect the efficient financing costs of a benchmark efficient entity with similar risk.

The allowed rate of return provides a network service provider (NSP), such as SA Power Networks, a return on capital to service the interest on its loans and give a return on equity to investors. To estimate this cost, we consider the cost of the two sources of funds for investments—equity and debt:

- the return on equity is the return shareholders of the business will require to attract new investment
- the return on debt is the interest rate the distributor pays when it borrows money to invest in capex.

We consider that efficient distributors would fund their investments by borrowing 60 per cent of the required funds, while raising the remaining 40 per cent from equity. We consider certainty and predictability of outcomes in rate of return issues will materially benefit the long term interest of consumers.

When a distributor spends money on an asset, for example a new substation, the value of that substation is added to its RAB. The value of the RAB is multiplied by the allowed rate of return to determine the total return on capital the distributor can recover from consumers.³⁷ By setting a rate of return based on a benchmark, rather than the actual costs of individual businesses, a distributor has an incentive to finance its business as efficiently as possible.

After extensive consultation, we have developed a guideline that sets out our intended approach for determining the rate of return.³⁸ We published the Rate of Return Guideline in December 2013.³⁹ The guideline is not binding, but if we or the distributors seek to depart from it the rules require that we must set out reasons for doing so.

We recently published our draft decisions for eight electricity and gas network service providers across NSW, ACT and Tasmania (November 2014 draft decisions).⁴⁰ Those draft decisions were the first time we have undertaken a full review of rate of return proposals (as part of a regulatory determination process) since we published the guideline. In those draft decisions, we applied the guideline after carefully considering a large amount of material submitted to us. We were satisfied that applying the approach and methodologies set out in the guideline result in an allowed rate of return that achieves the rate of return objective. Our findings were largely consistent with those at the time we made the guideline. However, we will consider the rate of return proposals from Energex and Ergon Energy taking into account the merits of the arguments they put forward, rather than what we determined in our draft determinations for the other network service providers.

³⁵ SA Power Networks, *Regulatory proposal*, p. 342.

³⁶ AER, *Rate of return guideline*, December 2013.

³⁷ NER, cl. 6.5.2(a).

³⁸ AER, *Rate of Return Guideline*, December 2013.

³⁹ AER, *Rate of Return Guideline*, December 2013.

⁴⁰ www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements

Questions

Do you consider any departures from the Rate of Return Guideline are justified?

In particular, do you have any comments on the departures from the Rate of Return Guideline proposed by SA Power Networks?

5.1 SA Power Networks' proposed overall rate of return

Table 7 below summarises SA Power Networks' rate of return proposal. The first row shows the overall rate of return, or weighted average cost of capital (WACC), proposed by SA Power Networks. The following rows show its proposed values for the individual components that, when combined, make up the WACC. These are the return on equity, return on debt, gearing ratio and the value of imputation credits.

Table 7 SA Power Networks' proposed rate of return

Overall WACC	7.62
Return on equity	10.45
Return on debt	5.74
Gearing	60 per cent
Value of imputation credits	0.25

Source: SA Power Networks, *Regulatory proposal*, p. 342.

Regulated rate of return

The investment environment has improved since our last determination for SA Power Networks, made during 2009 and early 2010. That determination was made during the uncertainty surrounding the global financial crisis. This resulted in us setting high rates of return for SA Power Networks for the 2010–15 period. This allowed rate of return largely reflected the risks perceived across the broader economy in the wake of significant turmoil in global financial markets. Since our last determination, interest rates and perceptions of economy wide risk have eased. As a consequence, lower rates of return may now be more appropriate.

We note SA Power Networks has used methods other than those set out in the Rate of Return Guideline to develop its proposed rate of return. While we consider the guideline sets out an appropriate approach, we do not wish to preclude stakeholder submissions proposing alternative approaches to both the guideline and SA Power Networks' proposal.

We also note that the return on debt numbers apply only for the first regulatory year (2015–16). SA Power Networks has proposed to annually update the return on debt.

Diversions from the Rate of Return Guideline

SA Power Networks' rate of return proposal has departed from the guideline for the following rate of return components:

- estimating the return on equity
- estimating the cost of debt
- estimating the value of imputation credits.

5.2 Return on equity

SA Networks did not use the foundation model approach set out in the guideline. Rather, it used an approach developed by SFG Consulting, which takes a weighted average of return on equity estimates from four financial models.⁴¹ This approach (subject to recent updates for market data on the risk free rate by SFG Consulting) was previously proposed by Jemena Gas Networks and ActewAGL, and reviewed by us in the recent draft decisions.⁴²

The guideline recognises there is not one perfect model to estimate the return on equity. Rather, we apply an iterative six step process (foundation model approach) which also draws on a variety of models and information we have assessed as relevant. We use a range of models, methods, and information to inform our return on equity estimate. We may use this information to set the range of inputs into the foundation model. Or we may use it to assist in determining a point estimate, within the range of estimates of overall return on equity resulting from the foundation model.

In our recent draft decisions, we were satisfied that the Sharpe–Lintner capital asset pricing model (SLCAPM) stands out as the superior model for our purposes. We therefore adopted it as the foundation model. The SLCAPM is estimated by adding to the risk free rate to the product of the equity beta and market risk premium.

Our approach is to estimate the risk free rate based on market conditions that prevail as close as possible to the commencement of the regulatory control period.

The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium over and above the estimated risk free rate at a given time. In our November 2014 draft decisions, we determined an equity beta of 0.7 and a market risk premium of 6.5 per cent, resulting in an equity risk premium of 4.55 per cent. We compared our 4.55 per cent equity risk premium with a range of other information. We were satisfied that our SLCAPM foundation model return on equity estimate is a reasonable estimate of efficient equity finance costs for a benchmark efficient entity.

SA Power Networks proposed an equity beta of 0.82 and a market risk premium of 7.72 per cent under its multiple model approach, but submitted that if its approach is not acceptable then an equity beta of 0.91 should be applied.⁴³

5.3 Return on debt

SA Power Networks has departed from the guideline to estimate the return on debt, on some matters. It has proposed to use a benchmark credit rating of BBB, rather than BBB+. It also proposed

⁴¹ SA Power Networks, *Regulatory proposal*, p. 317–319. Also see: SFG, *The required return on equity for regulated gas and electricity network businesses*, May 2014; SFG, *Updated estimate of the required return on equity*, September 2014.

⁴² JGN, *Access arrangement information*, June 2014, pp. 95–96; ActewAGL, *Regulatory proposal*, 2 June 2014 (resubmitted 10 July 2014), p. 261. AER, *Draft decision Jemena Gas Networks 2015–20, Attachment 3: Rate of return*, November 2014; AER, *Draft decision ActewAGL 2015–19, Attachment 3: Rate of return*, November 2014.

⁴³ SA Power Networks, *Regulatory proposal*, pp. 317–319. SA Power Networks did not specifically propose an MRP value, it proposed a required return on the market portfolio of 11.15 per cent. However, the return on the market portfolio estimate of 11.15 per cent equates to an MRP of 7.72 per cent, according to SFG Consulting's report for SA Power Networks. See: SFG, *Updated estimate of the required return on equity*, September 2014, p. 4.

incorporation of a 'new issue premium'.⁴⁴ However, in other respects, SA Power Networks' proposal is consistent with the guideline. This includes that SA Power Networks proposed transitional arrangements, consistent with the guideline, in moving from the old to the new regulatory approach for debt.

Approach

To estimate the return on debt, the Rate of Return Guideline proposes a ten year trailing average portfolio approach, with annual updates, after a period of transition. Our proposed transitional arrangement recognises the importance of transitioning from one benchmark approach to another benchmark approach. Under our proposed transitional arrangement, we would set 100 per cent of the allowed return on debt for the first year of the 2015–20 period based on current observed corporate bond yields. For the second year (2016–17), we would set 90 per cent of the allowed return on debt based on then-current corporate yields. For the third year we would set 80 per cent of the allowed return based on then-current corporate yields. And so on.

After ten years (covering two regulatory control periods), then-current observed bond yields would no longer impact at all on the allowed return on debt. For each of those ten years, progressively more of the allowed return on debt would be based on our proposed ten year trailing average portfolio approach. After the ten year transition period, 100 per cent of the allowed return on debt would be based on the ten year trailing average portfolio.

Implementation

The guideline also sets a benchmark credit rating of BBB+, based on the median credit rating for a sample of Australian utilities from 2002 to 2012. SA Power Networks has departed from the guideline in regard to the benchmark credit rating. It has proposed to apply a benchmark credit rating of BBB. It is not clear what impact (if any) the proposed change in credit rating would have; given the two possible data series' providers (the RBA and Bloomberg) both publish broad BBB rated data series.

In the Rate of Return Guideline we proposed to apply the published yields from an independent third party data service provider for estimating the prevailing return on debt for each service provider during the averaging period. In April 2014, we released an issues paper seeking submissions on which third party data service provider we should use to estimate the return on debt.⁴⁵ In our November 2014 draft decisions on the proposals from other service providers, we formed a position on the choice of third party data series.⁴⁶ Our draft decision was to annually update the trailing average portfolio return on debt, over the service provider's averaging period, using a simple average of:

- the RBA data series (specifically, the RBA broad-BBB rated 10 year curve), and
- the Bloomberg BVAL data series (specifically, the Bloomberg broad-BBB rated 7 year BVAL curve, where available, and otherwise the Bloomberg BBB rated 5 year BVAL curve).

We adopted that position because we were not satisfied that either data series is clearly superior to the other. Our position was supported by advice from Lally.⁴⁷ A simple average of two curves in these

⁴⁴ SA Power Networks, *Regulatory proposal*, pp. 338–341.

⁴⁵ AER, *Return on debt: Choice of third party data service provider – Issues paper*, April 2014.

⁴⁶ <http://www.aer.gov.au/>

⁴⁷ Lally, *Implementation issues for the cost of debt*, pp.3-6.

circumstances is also consistent with the Tribunal decision in ActewAGL where the Tribunal concluded that:⁴⁸

if the AER cannot find a basis upon which to distinguish between the published curves, it is appropriate to average the yields provided by each curve, so long as the published curves are widely used and market respected.

Further, our draft decision on the other service providers' proposals was also to make certain adjustments to the RBA and BVAL data series.⁴⁹ These adjustments are to match the return on debt with benchmark 10 year debt term, to enable the data series to be implemented over the service providers' averaging periods, and to enable the change in revenue resulting from the annual debt update to occur via the automatic application of a formula that is specified in the determination, consistent with the rules.⁵⁰

5.4 Value of imputation credits

SA Power Networks has proposed a value of imputation credits of 0.25, which is lower than the 0.5 proposed in the guideline. The value proposed by SA Power Networks is determined as the product of:

- a distribution rate of 0.7, consistent with the guideline
- a utilisation rate of 0.35, which is lower than the 0.7 in the guideline.⁵¹

Under the Australian taxation system, investors can receive an 'imputation credit' for income tax paid at the company level. For investors that meet certain eligibility criteria, this credit can be used to offset their tax liabilities. Imputation credits are a benefit to investors in addition to any cash dividend or capital gains from owning shares.

The rules account for the value of imputation credits through an adjustment to the company income tax building block allowance. The lower the value of imputation credits (known as 'gamma'), the larger the revenue allowance for the distributor. The guideline proposes that the value of imputation credits would be estimated as a market-wide parameter, rather than estimating this on an industry or business specific basis. Under the guideline, it would be determined as the product of:

- a distribution rate (referred to in the guideline as the 'payout ratio'), which represents the proportion of imputation credits generated by the benchmark entity that is distributed to investors
- a utilisation rate, which is the extent to which investors can use the imputation credits they receive to reduce their tax or to get a refund.

The distribution rate would be estimated using the cumulative payout ratio approach. This approach uses ATO tax statistics to calculate the proportion of imputation credits generated (via tax payments)

⁴⁸ In this decision, the issue before the Australian Competition Tribunal was the choice between the Bloomberg BFVC and the CBASpectrum curve, neither of which are currently published. See: *Application by ActewAGL Distribution [2010] ACompT4*, 17 September 2010, paragraph 78.

⁴⁹ For the RBA curve, our draft decision is to interpolate the monthly data points to produce daily estimates, to extrapolate it to an effective term of 10 years, and to convert it to an effective annual rate. For the BVAL curve, our draft decision is to extrapolate it to 10 years using the spread between the extrapolated RBA 7 and 10 year curves, and to convert it to an effective annual rate.

⁵⁰ NER, cl. 6.5.2(l).

⁵¹ SA Power Networks actually referred to the utilisation rate as 'the value of distributed imputation credits to investors who receive them', and labelled this parameter the Greek letter 'theta'. We intend to discuss the alternative labelling and interpretations of the utilisation rate.

that has been distributed by companies since the start of the imputation system. At the time of the guideline's publication, this approach produced an estimate of 0.7 for the payout ratio.

The utilisation rate would be estimated using the body of relevant evidence with regards to its strengths and limitations, checked against a range of supporting evidence.

In the guideline, our assessment of this evidence produced an estimate of 0.7 for the utilisation rate. The guideline therefore proposed an estimate of 0.5 for the value of imputation credits, based on a distribution rate of 0.7 and a utilisation rate of 0.7.

In our November 2014 draft decisions on the proposals from other service providers, we broadly maintained the approach set out in the guideline to the value of imputation credits, but re-examined the relevant evidence and estimates. Based on expert advice, we also clarified our definition of the utilisation rate as the utilisation value to investors in the market per dollar of imputation credits distributed. This re-examination, in addition to new evidence and advice considered since the guideline, led us to depart from the 0.5 value of imputation credits we proposed in the guideline. Instead, we chose a value for imputation credits of 0.4 from within a range of 0.3 to 0.5. Importantly, we considered that a value of imputation credits of 0.4 provides service providers with a reasonable opportunity to recover at least their efficient corporate tax costs, and that this value is consistent with the building block framework embedded in the rules.

6 Consumer engagement

SA Power Networks has submitted its consumer engagement strategy and descriptions of feedback it received from consumers and other stakeholders. Consumer engagement is an important issue for our distribution determination.

As required by the rules, we will have regard to the nature of consumer engagement undertaken and the outcomes of that engagement in considering the proposals put to us by SA Power Networks.⁵² We will consider how SA Power Networks:

- equipped consumers to participate in consultation
- made issues tangible to consumers
- obtained a cross section of views
- considered and responded to consumer views.

We will make our assessment on a case-by-case basis drawing on SA Power Networks' proposal and submissions from the CCP and other stakeholders. We will also have regard to the extent to which SA Power Networks' opex and capex proposals reflect consumer concerns.⁵³

Questions

Do you consider SA Power Networks has adopted our consumer engagement guideline to build genuine consumer engagement across all business activities?

Do you consider that SA Power Networks' proposals reflect the engagement it had with you and issues you raised? If SA Power Networks did not agree with consumer views, did it explain why?

Did SA Power Networks provide you with options and scenarios for service and price trade-offs?

6.1 Distributors' consumer engagement

This section summarises the consumer engagement strategies and activities described by SA Power Networks in its regulatory proposal. We consider this is a valuable resource for readers to quickly get a sense of SA Power Networks' consumer engagement approach. However, we also encourage you to review the regulatory proposals' consumer engagement materials and submit to us your views.

SA Power Networks submitted it:

- initiated a consumer engagement program titled 'TalkingPower', incorporating an evidence based process, provision of relevant information to stakeholders and methodical assessment of customers' issues and potential means to address them
- undertook customer and stakeholder workshops, online surveys, customer integration workshops, targeted strategic workshops, willingness to pay research and consultation on SAPN's Directions and Priorities paper as well as ongoing consultation through the TalkingPower website

⁵² AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, p. 36.

⁵³ NER, cl. 6.5.6(e)(5A) and 6.5.7(e)(5A).

- involved 8,590 customers or stakeholders in its TalkingPower program, advertised to an online survey audience of 575,000 people and had 4,994 unique visitors to the TalkingPower website, with 573 stakeholders involved in its bilateral engagement measures.
- identified key customer 'insights'.

Throughout SA Power Networks' regulatory proposal it set out stakeholder and customer issues and SAPN's response, including where it has not adopted stakeholder or consumer views.

6.2 Our consumer engagement guideline

To assist service providers, such as SA Power Networks, we developed a consumer engagement guideline for network service providers.⁵⁴ The guideline centres on:

- best practice principles to drive consumer engagement
- a commitment from service providers to continuously improve engagement across all business operations on issues that are significant to the business and its consumers.

The guideline is not prescriptive. Rather, it places the onus on the distributors to develop consumer engagement strategies and activities that best suit their business.

6.3 Our own consumer engagement

For the last 12 months we have engaged with consumer and other stakeholder groups, in addition to SA Power Networks, about the 2015–20 electricity determination. We have heard strong views about the adverse impact on consumers of electricity price increases during the 2010–15 period. It is clear that consumers and stakeholder groups are seeking price relief and greater transparency from the distributors. Our Consumer Challenge Panel has been engaging with consumer groups and stakeholders and advising us on issues it considers relevant to consumers.

⁵⁴ AER, *Consumer engagement guideline for network service providers*, November 2013.

7 Other issues

This chapter discusses some additional key issues for this reset which do not fall neatly into the previous chapters on capex, opex, rate of return and consumer engagement:

- metering exit fees
- cost pass throughs
- service reliability incentives.

7.1 Metering

In our Framework and Approach paper,⁵⁵ published in April 2014, we proposed to reclassify standard metering services for residential and small business consumers (type 5 and 6 meters) as alternative control, from standard control. This means that consumers using these metering services will pay for them, rather than these costs being included in standard network charges paid by all consumers.

Our reclassification of type 5 and some type 6 metering services is intended to facilitate the competitive provision of metering services, including new smart meters. This is one component of a broader range of reforms to the way metering services are provided, currently being considered under a rule change proposal, initiated by the COAG Energy Council, by the Australian Energy Market Commission. The goal of these reforms is to remove SA Power Networks' existing monopoly on metering services and to enable a range of new services, both inside the consumer's home or business and for the distributors themselves. Smart meters will also allow for more cost reflective pricing than the traditional type 5 and 6 meters.

We consider a valuable outcome of more efficient pricing structures enabled by smart meters will be reduced pressure on the distributors to build additional infrastructure to meet high demand periods. Instead, consumers and distributors will be better able to manage electricity demand to optimise existing network assets, reducing the costs that consumers would otherwise be asked to pay for.

As a standard control service, the value of a type 5 or 6 meter is included in SA Power Networks' RAB. This value, or 'cost' from the perspective of the consumer, is recovered from all consumers over time, rather than up front. When a consumer switches from a traditional type 5 or 6 meter to a new smart meter, the value of the meter will be removed from the RAB. The distributor will earn no more revenue to cover the remaining value (cost) of that meter. That is, the distributor may be out of pocket.

To address this issue, SA Power Networks has proposed "exit" or "transfer" fees for consumers that switch to a third party meter provider. The proposed exit fees are intended to cover both the cost of the meter and administrative costs associated with its removal. The proposed transfer fees are for customers who switch from SA Power Networks to a third party meter provider but retain the physical meter, SA Power Networks has proposed a range of fees up to \$550.⁵⁶

Our initial view is that the exit or transfer fees proposed by SA Power Networks are likely to inhibit development of effective competition in the provision of metering services. This is because they will

⁵⁵ AER, *Final framework and approach for SA Power Networks—regulatory control period beginning 1 July 2015*, April 2014.

⁵⁶ SA Power Networks, *Regulatory proposal*, p. 356.

be a disincentive for consumers to switch to smart meters. In turn, the potential benefits of using smart meters will be less likely to emerge.

We are working with SA Power Networks through this determination process to develop an approach allowing them to recover their metering related costs without establishing a significant barrier to the adoption of smart meters from third parties. We invite consumers and other stakeholders to submit views to us, to inform our preliminary decision.

7.2 Cost pass throughs

The rules permit the distributors to apply to us, during a regulatory period, for their prices to be adjusted because an unexpected and material cost arises or, in some cases, if actual costs are materially different to the allowances included in our original determination.⁵⁷ While cost pass throughs may be opex in nature, they may also be capex or a combination of different cost categories. For convenience, we discuss cost pass throughs here.

Pass throughs are only permitted if they are for events listed in the distributors' distribution determinations or defined in the rules. Once a distribution determination has been finalised, we are required to approve a cost pass through application from a distributor if it satisfies the relevant requirements in our determination and the rules.

A number of pass through events are already defined by the rules:

- regulatory change event
- service standard event
- tax change event
- retailer insolvency event.

For the 2015–20 regulatory period, SA Power Networks has proposed additional pass throughs for:

- Kangaroo Island cable failure event
- natural disaster event
- liability above insurance cap event
- insurer credit risk event.
- native title event
- general nominated pass through event.

We seek your views on the pass through events nominated by SA Power Networks. In particular, should they be recovered as part of a cost pass through if such events occur, or is it more appropriate for these potential impacts to be reflected in SA Power Networks' allowances. Alternatively, should SA Power Networks manage the risk of these events using its existing resources.

⁵⁷ NER, cl. 6.6.1.

7.3 Additional incentive to improve supply reliability during major storms and heatwaves

SA Power Networks has proposed changes to the financial incentives it is paid for supply reliability improvement. The incentive scheme operates in a way that if supply reliability is improved, SAPN receives a financial reward. Once, improvement is made, future performance targets are tightened so customers do not pay for improved reliability twice. The reverse occurs if performance worsens.

The current incentive works such that performance during SA Power Networks' 4 to 6 most severe storms/heatwaves each year do not impact on the incentive payments/penalties. SA Power Networks now proposes a different approach. Severe weather events that impact of the scheme's outcome would be reduced to 2 to 4 days each year. Details of SA Power Networks' suggested new approach are described in its regulatory proposal attachments 23.13 and 23.14.

According to SA Power Networks, had the new method applied during the past 4 years, its revenue would have been increased by 1.25 per cent on average. The changes suggests SA Power Networks' performance during recent adverse weather events was better in the past 4 years than in earlier periods. Based on SA Power Networks' past performance, we estimate that the potential impact on customers' bill would be around 1 per cent.

The significance of this proposed change is that more of SA Power Networks' supply reliability during storms and heatwaves will be subjected to financial incentives, rather than being excluded. While we can expect SA Power Networks' performance to improve during such events, customers will likely need to pay more.

We seek stakeholders' opinions on SA Power Networks' proposal— in particular, whether consumers would value further improvement in supply reliability during severe storms and heatwave days in terms of reduction in average supply restoration time and fewer supply interruptions. It should be noted that the incentive applies to network average performance outcome. Hence, improvements may not be universal across all parts of South Australia.

8 Interrelationships between components of our decision

The NEL requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision. When considering any constituent component of a decision as complex as a distribution determination, it is important to also consider the interrelationships between constituent components. Ultimately, a distribution determination is an overall decision and must be considered as such. Considering constituent components in isolation ignores the importance of these interrelationships.

To assist you in providing us with submissions on the interrelationships inherent in the distributors' regulatory proposals, this attachment describes the building block model and outlines some of the interrelationships we are likely to take into account.

Question

How should we balance the interrelationships between building block components when making our decision on SA Power Networks' proposal?

8.1 The building block model

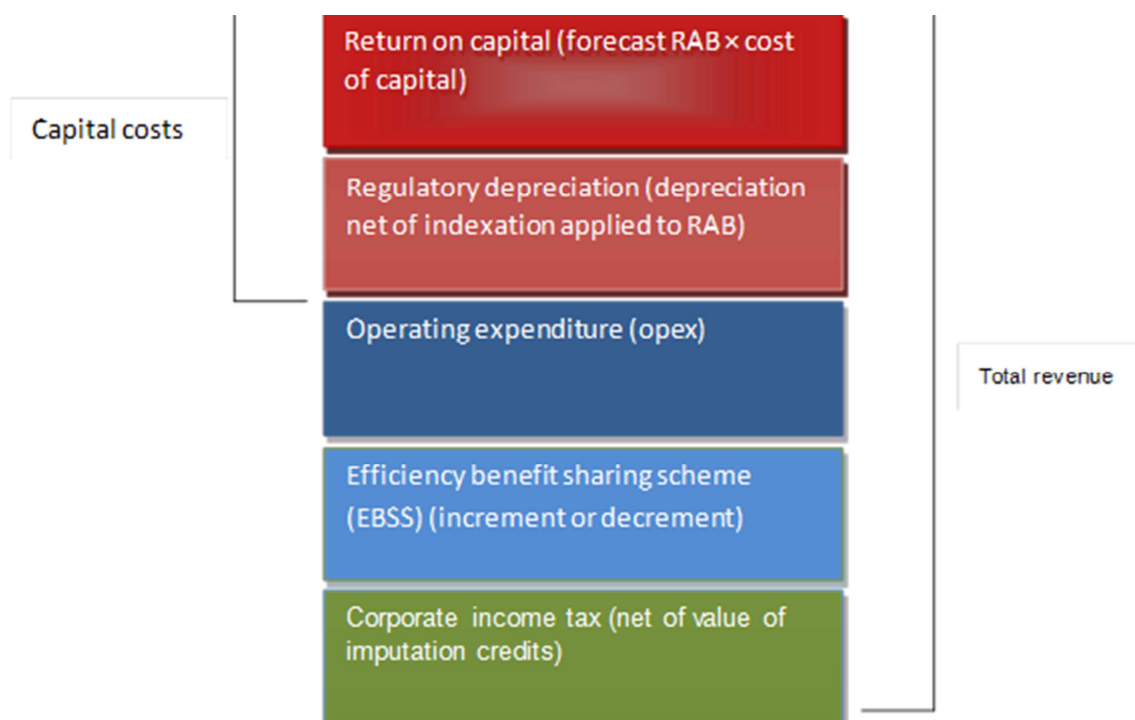
If we do not accept SA Power Networks' proposal, we must determine the efficient cost of providing distribution services, subject to the requirements of the rules. To do this, we assess the total revenue required to provide distribution services for each year of the period. In accordance with the rules, we use the building block model to determine the annual revenue requirement. The underlying cost elements include:

- a return on the regulatory asset base (return on capital)
- depreciation of the regulatory asset base (return of capital)
- opex
- increments or decrements resulting from the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of a distributor's asset base and therefore the return on capital and return of capital building blocks.

Figure 10 below illustrates the building block model.

Figure 9 The building block approach to determining regulated revenues



8.2 Interrelationships between building block components

In some cases, the separate building block components may be substitutes, so that increasing one may lead to decreasing another. In other cases, increasing one component will increase another. There may not be a single optimal combination. Rather, several combinations may provide an efficient level of revenue. Below, we describe some of the interrelationships we consider may be important to our assessment of the distributors' proposals.

Repair or replace assets

Maintaining existing assets incurs opex costs. However, if those assets are replaced instead of being maintained, the distributor incurs capex costs. The decision to repair or replace assets can affect ongoing opex costs, in that newer assets may require less maintenance than older assets.

Building assets increases the return on capital and depreciation

The more capex investment undertaken by a distributor, the larger its future return on capital and depreciation allowance. This is because capex contributes to the size (value) of a distributor's asset base. The return on capital is equal to the rate of return multiplied by the value of the distributor's asset base. So the larger the asset base, the larger the dollar amount return on capital and therefore how much revenue they are allowed to recover. In the same way, the distributor's depreciation allowance becomes larger in proportion to the size of the asset base being depreciated.

More assets require more maintenance

Depending on the type of capex investments made by a distributor, additional investment may create need for more opex spending. This is because, in principle, a large asset base requires more maintenance than a small asset base. This effect may be offset by capex investment that creates operational efficiencies, or avoids the increasing opex required to extend the operating life of ageing assets, as described above.

Incentive schemes and revenue allowances

Schemes to provide SA Power Networks with incentives to become more efficient, such as the EBSS, affect the revenue allowances we determine for capex and opex. For example, by seeking to maximise its EBSS payment, a distributor may uncover efficiencies in its maintenance activities. In the short term, the distributor is allowed to retain the savings it achieved. But in the longer term, the savings reduce the distributors' opex allowance, reducing prices. Because capex spending can either increase or decrease the need for opex costs to be incurred, the EBSS incentive may also influence both short and long term capex allowances. Other incentive schemes, such as the service target performance incentive scheme, target capex more directly.

A range of further interrelationships exist within the building block elements, where our decision on technical variables influence one or more of the building blocks themselves. These include:

- the economic life of assets — affects return on capital, capex, opex
- step changes — affects capex, opex, incentive schemes, pass throughs
- base year adjustments — affects opex, capex, incentive schemes
- forecast inflation — affects all forecasts
- related party transactions — affects capex, opex.

A Background to our assessment

This appendix provides information about us, SA Power Networks and the regulatory framework we administer.

A.1 The Australian Energy Regulator

We are Australia's national energy market regulator and an independent statutory authority. Our functions, set out in the NEL and rules, mostly relate to energy markets in eastern and southern Australia. These functions include:

- setting the prices charged for using energy networks (electricity poles and wires and gas pipelines) to transport energy to customers
- monitoring wholesale electricity and gas markets so suppliers comply with the legislation and rules, and taking enforcement action where necessary
- publishing information on energy markets, including the annual State of the Energy Market report and more detailed market and compliance reporting, to assist participants and the wider community
- assisting the Australian Competition and Consumer Commission with energy-related issues arising under the Competition and Consumer Act, including enforcement, mergers and authorisations.

The NEL and rules provide the legal framework under which we operate. Chapter 6 of the rules contains timelines and processes for the regulation of electricity distribution businesses. It provides that regulated distribution businesses must periodically apply to us to assess their revenue. Typically, this happens every five years. The application, or revenue proposal/, starts a process often referred to as a revenue reset, or simply a 'reset'.

We are required to exercise our functions in a manner that will advance the National Electricity Objective (NEO). The NEO in turn is supported through the revenue and pricing principles and the various objectives, criteria and elements within the rules. The NEO is:⁵⁸

...to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

- (a) price, quality, safety, reliability and security of supply of electricity; and
- (b) the reliability, safety and security of the national electricity system.

We consider that the NEO is most likely to be advanced where consumers are offered a reasonable level of service at the lowest sustainable price. In most industries, this outcome is achieved through the operation of competition. However, in the electricity network industry the usual competitive disciplines do not operate.

⁵⁸ NEL, s.7.

The electricity network businesses are natural monopolies and the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the service quality and price the distributors offer.

The NEL and rules aim to reflect the competitive process by empowering us, as regulator, to make decisions that are in the long term interests of consumers. In particular, we might need to require the distributors to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory discretion to balance the NEO's various factors.

It is important to recognise that there is no sole correct answer that will contribute to the achievement of the NEO. The nature of decisions in the energy sector is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.⁵⁹ At the same time, however, there are a range of outcomes that are unlikely to advance the NEO to a satisfactory extent.

For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.⁶⁰ This could have significant longer term pricing implications for those consumers who continue to use network services.

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, creating longer term problems in the network.⁶¹ This can have adverse consequences for safety, security and reliability of the network. We would like to hear views on how the NEO is best reflected in our decision.

A.2 Who is SA Power Networks?

The electricity supply chain begins with a wholesale market in which generators produce electricity and sell it through a central dispatch process. The high voltage transmission network transfers electricity over long distances from where it is generated to where consumers need it. The distributors' networks connect the high voltage transmission network to customers. Distribution networks criss-cross urban and regional areas to provide electricity to every electricity consumer.

SA Power Networks is a monopoly provider of electricity distribution network services in South Australia. It is authorised by the South Australian Government as the sole provider of electricity via its low voltage network throughout its service area. SA Power Networks is responsible for the planning, design, operation and maintenance of its distribution network.

SA Power Networks is privately owned. Formerly known as ETSA Utilities, it was re-named in 2012. It was previously a South Australian Government owned corporation named the Electricity Trust of South Australia. SA Power Networks is currently owned by the Cheung Kong Group (51 per cent) and Spark Infrastructure (49 per cent).

⁵⁹ *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.

⁶⁰ NEL, s. 7A(7).

⁶¹ NEL, s. 7A(6).

A.3 The regulatory framework

We must assess SA Power Networks' regulatory proposal under version 58 of the rules with the modifications required by the relevant transitional provisions in chapter 11 of the rules. Version 58 is available at the Australian Energy Market Commission (AEMC) website. Following changes made to the rules by the AEMC in 2012, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program.

The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.⁶² The resulting guidelines support our decision making framework as set out in section 16 of the NEL.⁶³ Our Better Regulation guidelines are:

Expenditure forecast assessment guideline

Assessing expenditure proposals from businesses.

Rate of return guideline

Determining the allowed rate of return businesses earn on their investments.

Expenditure incentives guideline

Creating the right incentives to encourage efficient spending by businesses.

Consumer engagement guideline for network service providers

Implementing consumer engagement strategies that are effective for all stakeholders.

Shared asset guideline

Sharing the revenue networks earn from shared assets with consumers.

Confidentiality guideline

Managing confidential information for an effective regulatory determination process.

The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged.⁶⁴ The extent of our consultation was unprecedented for the AER. This was very important for testing our views and hearing from the full range of stakeholders. Our exhaustive consultation and engagement gives us confidence the approaches set out in the guidelines will result in decisions that contribute to the achievement of the NEO and form an important baseline in future decision making. In particular, we directly engaged consumers in the process through our Consumer Reference Group.⁶⁵

We facilitated direct engagement between network service providers and consumers through participation in forums and the almost 140 meetings held with stakeholders over the course of the

⁶² AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

⁶³ See our website: www.aer.gov.au/Better-regulation-reform-program

⁶⁴ AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

⁶⁵ AER, *Assessment of the Consumer Reference Group*, March 2014. This document includes information on training provided to CRG members, meetings and CRG member feedback. It can be accessed at www.aer.gov.au/node/19166.

program.⁶⁶ Consumers and network service providers also made written submissions on our draft guidelines and explanatory statements, responded to advice from our experts and provided their own consultant reports.

In the process established by the rules, SA Power Networks has the first opportunity to propose a price/service offering. Its application, or regulatory proposal, starts a process often referred to as a revenue reset, or simply a 'reset'. We will assess that proposal against the NEO and the rules to form a view on whether a distributor's proposal is in the long term interests of consumers. Where it is not, we will not accept the proposal, and instead substitute our own decision.

Because this is an intrusive process we exercise our role with care and diligence. We consult broadly and test our views, employing approaches that are widely accepted and carefully considered, such as those articulated in the guidelines.

Transitional arrangements applicable to this reset

The AEMC recognised that there was a need to put in place transitional arrangements for the current round of resets. Under the transitional arrangements applying to SA Power Networks for the 2015-2020 period, commencement of the AER's revenue determination process is delayed by five months.

The rules require us to publish SA Power Networks' regulatory proposals, invite submissions and hold a public forum on the regulatory proposals and the AER's proposed negotiated distributions service criteria.⁶⁷ Although the rules do not require us to publish an issues paper, we have decided to publish this issues paper in the interests of transparency and to assist stakeholder input to the process.

At the same time that we publish our preliminary determinations for the 2015-20 period, we are required to invite submissions on the revocation and substitution of those determinations.⁶⁸ Distributors may make a submission in the form of revisions to the regulatory proposal.⁶⁹

Although we are not required to do so under the transitional arrangements, we will hold a public forum following the publication of our preliminary determinations. We also propose to provide stakeholders with the opportunity to make submissions on any revised regulatory proposals submitted by SA Power Networks before we revoke the preliminary determination and make our final determination in substitution for it.

A.4 Our framework and approach

We released our Framework and Approach (F&A) in April 2014.⁷⁰ This set out our intended approach to parts of the regulatory framework, such as service classification. In terms of our classification decisions, in summary we may:

- classify a service so that the distributor may recover related costs from all customers (standard control)
- classify a service so that the user benefiting from the service pays (alternative control)

⁶⁶ AER, *Overview of the Better Regulation reform package*, April 2014, pp. 20–21.

⁶⁷ NER, cl. 6.9.3(a) and 11.60.3(b)(3)(ii).

⁶⁸ NER, cl. 11.60.4(a).

⁶⁹ NER, cl. 11.60.4(b).

⁷⁰ www.aer.gov.au/node/20187; www.aer.gov.au/node/20186

- allow customers and distributors to negotiate the provision and price of some services—we will arbitrate should negotiations stall (negotiated distribution service)
- not classify a service—we have no regulatory control over this service or the prices charged by the distributor (unclassified service).

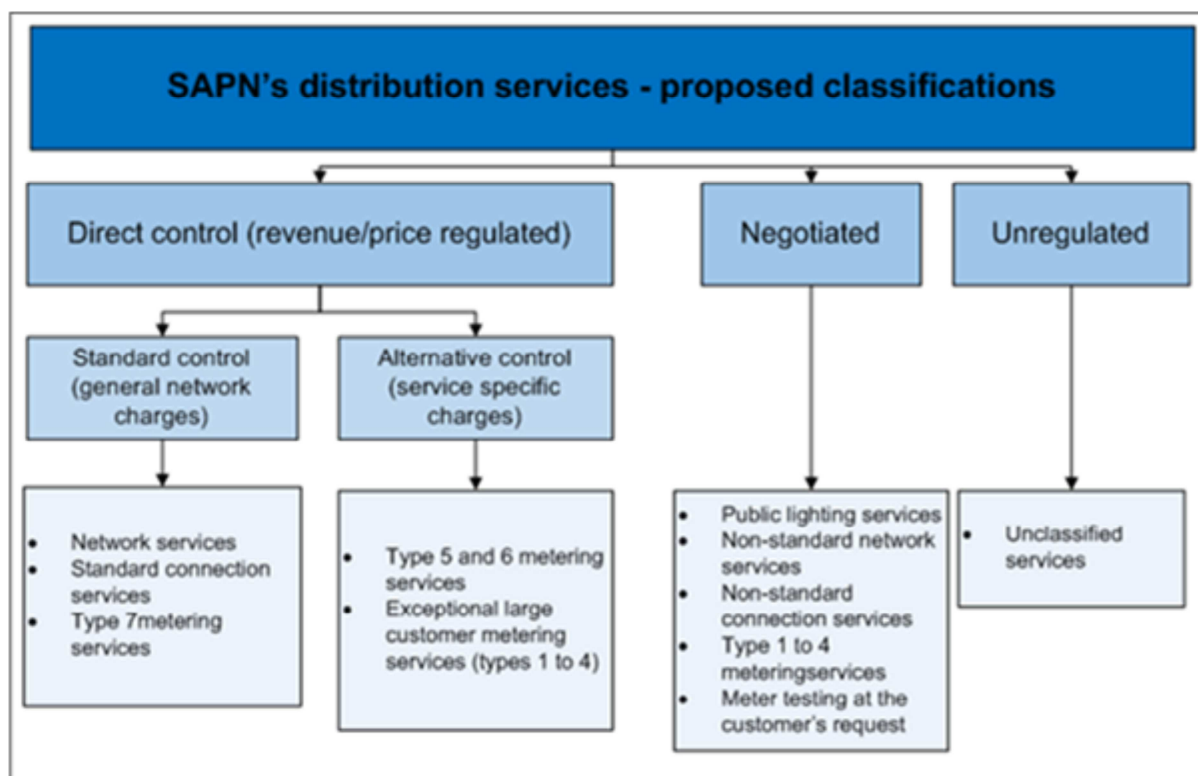
Standard control services represent the large majority of a distributor's revenue, reflecting the integrated nature of an electricity supply network. The distributors recover the cost of providing standard control services from all electricity customers through standard network charges—known as Distribution Use of System (DUoS) charges. It is the total cost of providing standard control services that this issues paper predominantly relates to. Services classified as alternative control are separately billed to individual electricity customers.

Figure 10 below shows our proposed service classifications for the 2015–20 period. We may only change our proposed classifications if we consider unforeseen circumstances arise.⁷¹ Our classifications are consistent with those for the 2010–15 period, with one important exception:

- type 5 and 6 metering services (simple accumulation and basic time of use meters) are reclassified as alternative control, from standard control.

These changes mean the costs of providing these services will now be excluded from the distributors' DUoS charges. In future they will be recovered from specific customers requiring those services, rather than from all customers.

Figure 10 AER proposed 2015–20 service classifications for SA Power Networks



Source: AER.

⁷¹ NER, cl. 6.21.3(b).

Metering reclassification

Our reclassification of type 5 and some type 6 metering services is intended to facilitate the competitive provision of metering services, including new smart meters. This is one component of a broader range of reforms to the way metering services are provided, currently being considered under a rule change proposal, initiated by the COAG Energy Council, by the AEMC. The goal of these reforms is to remove the existing monopoly on metering services enjoyed by the distributors and to enable a range of new services, both inside the consumer's home or business and for the distributors themselves. New meters will also allow for more cost reflective pricing than the traditional type 5 and 6 meters.

We consider a valuable outcome of more efficient pricing structures enabled by smart meters will be reduced pressure on the distributors to build additional infrastructure to meet high demand periods. Instead, consumers and distributors will be better able to manage electricity demand to optimise existing network assets, reducing the costs that consumers would otherwise be asked to pay for.