Draft decision

ElectraNet

Transmission determination

2013–14 to 2017–18

November 2012

AUSTRALIAN ENERGY REGULATOR

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Contents

Shortened forms

Shortened form	Extended form
AASB	Australian Accounting Standards Board
AARR	aggregate annual revenue requirement
ACCC	Australian Competition & Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	agreed maximum demand
AMP	asset management plan
ANZSIC	Australian and New Zealand Standard Industrial Classification
APR	Annual Planning Review
ASRR	annual service revenue requirement
capex	capital expenditure
CAPM	capital asset pricing model
CEG	Competition Economists Group
CGS	Commonwealth Government securities
CPI	consumer price index
DAE	Deloitte Access Economics
DRP	debt risk premium
EA	enterprise agreement
EBSS	efficiency benefit sharing scheme
EGW	electricity, gas and water
EGWWS	electricity, gas, water and waste services
EMCa	Energy Market Consulting associates
ESCOSA	Essential Services Commission of South Australia
ETC	South Australian Electricity Transmission Code
FAMD	forecast agreed maximum demand
kW	kilowatt
LPI	labour price index

LME	London Metals Exchange
MAR	maximum allowed revenue
MRP	market risk premium
MW	megawatt
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	national electricity objective
NER	National Electricity Rules
NTSC	negotiated transmission service criteria
opex	operating expenditure
PMM	project management methodologies
POE	probability of exceedance
PTRM	post tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
RIT–D	Regulatory Investment Test for Distribution
RIT–T	Regulatory Investment Test for Transmission
SASDO	South Australian supply and demand outlook
STPIS	service target performance incentive scheme
TAB	tax asset base
TALC	total asset life cycle
TNSP	transmission network service provider
TUOS	transmission use of system
WACC	weighted average cost of capital

Overview

This is the AER's draft decision on ElectraNet's transmission determination for the regulatory control period 1 July 2013 to 30 June 2018. It sets out the AER's draft decision on the amount of revenue that ElectraNet can recover from customers during this period. The AER applied the laws and rules governing the regulation of electricity transmission networks to make its draft decision.

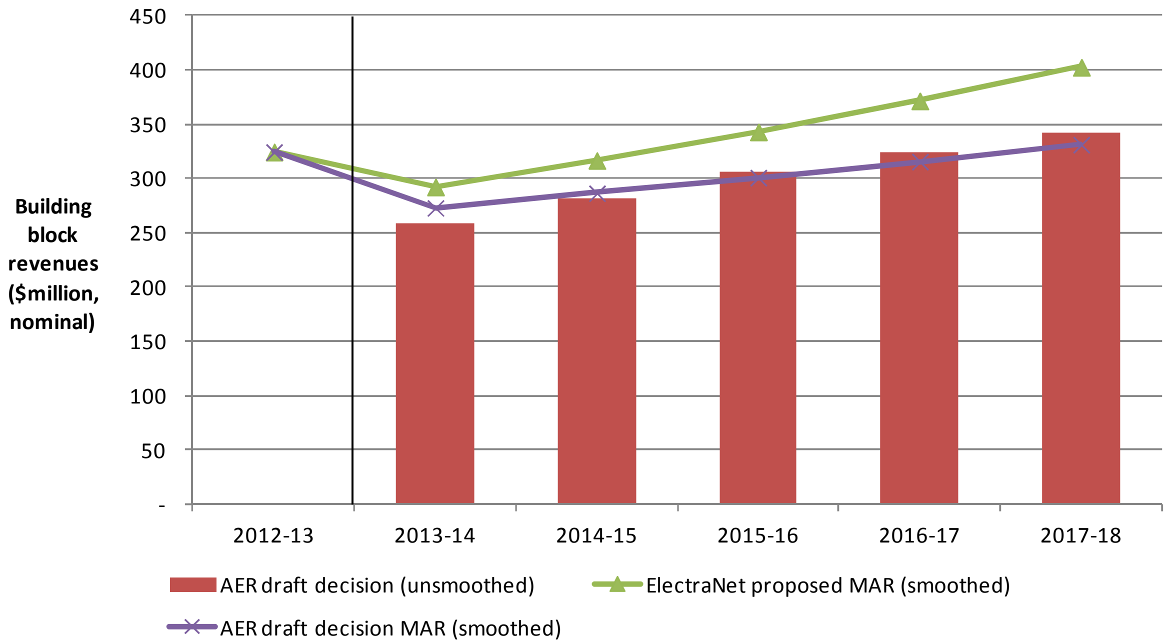
This draft decision also details a number of revisions that ElectraNet must make to its revenue proposal to make it acceptable under the National Electricity Rules (NER). ElectraNet can submit a revised revenue proposal following the AER's draft decision, and the AER will make a final decision on the revised proposal.

The AER's draft decision

The AER regulates ElectraNet under a revenue cap regulatory control mechanism. That is, the maximum revenue that ElectraNet is able to recover annually over the 2013–18 regulatory control period is determined by the AER's transmission determination.

The AER's draft decision has determined a total revenue cap of $1507.3 million ($nominal) for ElectraNet over the 2013–18 regulatory control period. This is 12.7 per cent lower than ElectraNet's proposal. Figure 1 shows the AER's draft decision and ElectraNet's proposed revenue requirement. The AER applied the CPI – X formula to smooth the revenue profile over the forecast 2013–18 regulatory control period. The X factor for this draft decision is –2.4 per cent per annum, meaning that smoothed revenues will increase (in real dollar terms) over the 2013–18 regulatory control period.

Figure 1 **AER draft decision on total revenue requirement**



Source: ElectraNet, *Proposed PTRM, ENET077*, May 2012; AER analysis.

Indicative price impact on customers

The AER estimates that its draft decision will result in a small decrease in average transmission charges of 0.1 per cent per annum ($ nominal) from 2012–13 to 2017–18.[1] This decrease is a result of the AER approved lower maximum allowed revenue (MAR). The factors driving the AER approved MAR is set out in this draft decision and in more detail in the attachments. In summary, the AER has updated the cost of capital to reflect current market data and the forecast expenditure to reflect efficient and prudent costs consistent with the rule requirements. The AER has also taken into account the lower growth in peak demand forecasts for South Australia.

The average increase in the AER approved MAR is 0.8 per cent per annum in nominal dollar terms, whereas the average increase in the forecast energy delivered in South Australia is about 0.9 per cent per annum. Given that the forecast energy is growing faster than the average increase of the MAR, average transmission charges are estimated to decrease from 2012–13 to 2017–18. Transmission charges make up about 8 per cent of an average residential customer's bill.

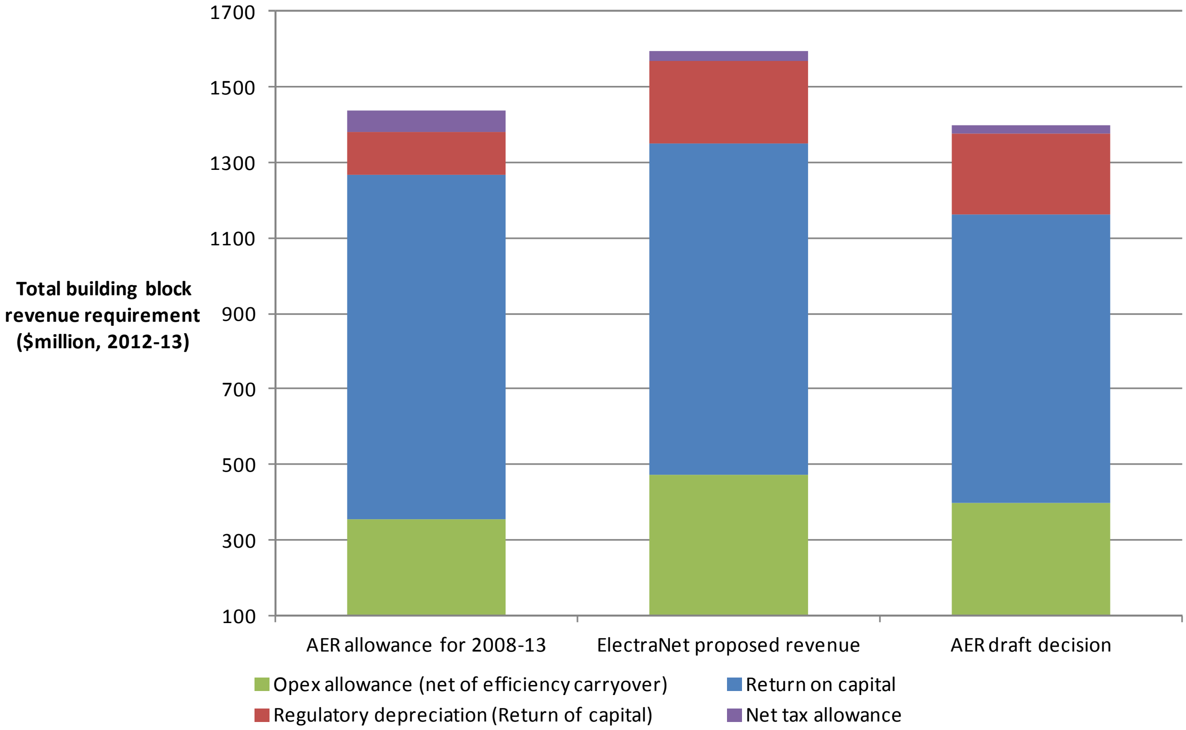
ElectraNet's underlying costs

Businesses like ElectraNet have a substantial investment in long-lived assets. As a result, the cost of capital is a major component of ElectraNet's total costs. ElectraNet must pay interest on its debt and provide a return to its shareholders. Since the last determination the cost of capital has decreased. ElectraNet proposed a nominal weighted average cost of capital (WACC) of 7.73 per cent which is much lower than the WACC of 10.65 per cent approved by the AER in its 2008 transmission determination. All things being equal, the lower cost of capital that currently prevails would be expected to result in a lower revenue requirement for ElectraNet. However, ElectraNet is proposing an increase in the forecast MAR over the approved revenue allowance in the 2008–13 regulatory control period.

Figure 2 shows the major components of ElectraNet's total costs between the 2008–13 (AER allowance), 2013–18 (ElectraNet revenue proposal) and the AER's draft decision revenue allowance for 2013–18 regulatory control period.

[1] The average transmission price impacts on South Australian customers have been estimated after accounting for both ElectraNet's and Murraylink's revenue proposals and draft decisions. These indicative figures are based on AEMO's 2012 energy forecast for South Australia.

Figure 2 **Comparison of ElectraNet's 2008–13 revenue, 2013–18 proposed revenue and AER 2013–18 draft decision revenue**



Source: AER analysis.

A key feature of ElectraNet's proposal is its emphasis on its governance and asset management systems. ElectraNet stated that its focus on governance and its substantial investment in its asset management systems enables it to manage its network in a highly efficient manner. The systems provide detailed objective information on the state of the network so that ElectraNet can make informed decisions based on identified risks.

The AER considers that ElectraNet has good governance and expenditure management frameworks in place to monitor and manage its network assets. ElectraNet's systems provide it with the capability to make decisions that balance risks against economic costs.

However, the AER considers that ElectraNet is not accessing the significant economic benefits available to it from the deployment and implementation of its new and enhanced asset management capabilities. ElectraNet has not given sufficient weight to its continuous improvement and innovation programs or to the efficiencies that are available through its enhanced systems. Its management decisions and its governance structures do not yet take full advantage of its enhanced asset management capabilities. As a result, the AER considers that ElectraNet's proposed expenditure is higher than necessary.

The AER considers that ElectraNet's improved asset management framework is a key driver of both capital expenditure and operating expenditure forecasts. ElectraNet proposed significant increases in expenditure categories that should benefit from the application of its enhanced asset management systems.

ElectraNet has spent substantial resources on its enhanced asset management system and is proposing to spend additional amounts in the next regulatory control period. The total cost of the system is estimated to be greater than $50 million. Customers are bearing the costs of the enhanced system, but they are not receiving the benefits that are available through ElectraNet effectively accessing its asset management capabilities. Consequently, the AER does not consider that ElectraNet's proposal satisfies the requirements of the NER. The AER considers that ElectraNet's proposed opex and capex should be reduced.

The AER considers there are three other significant features of the proposal that are not satisfactory.

First, ElectraNet's strategy of buying land and easements early is not an efficient and prudent approach to securing its requirements. ElectraNet proposed $66 million ($2012–13) for land and easement capex compared to actual land and easement capex of $2.7 million ($2012–13) during 2008–2011.

Second, ElectraNet has proposed a large portfolio of contingent projects worth $2.5 billion ($2012–13). ElectraNet stated it used contingent projects to meet its objective of keeping customer price impacts in line with movements in the consumer price index (CPI). However, the AER considers that using contingent projects to keep costs in line with CPI potentially removes the incentives for TNSPs to manage their network within the capex allowance. ElectraNet’s approach does not seem to be consistent with the regulatory framework as it treats contingent projects like pass throughs and resembles ‘cost of service regulation’. The AER has not accepted the proposed contingent projects including several that are triggered by a demand forecast increase which is less than ElectraNet’s high demand forecast. Accepting such projects is not appropriate because provision should be made for these projects in the ex ante allowance.

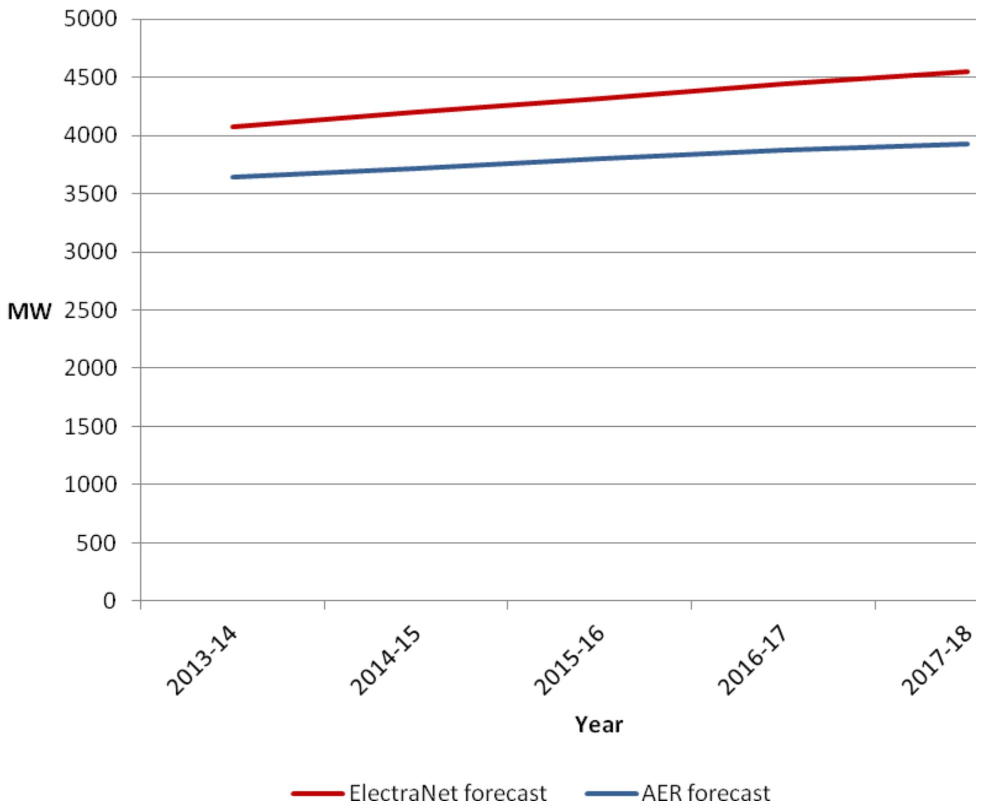
Third, ElectraNet has proposed augmentation and connection capex based on a peak demand forecast that is too high. Growth in peak demand, also referred to as maximum demand, is an important factor driving network augmentation and connection point capital expenditure. The reliability standards that ElectraNet must meet at each connection point, together with expected growth in peak demand influences the load driven capital expenditure projects and their timing. The Australian Energy Market Operator (AEMO) is currently assessing its regional maximum demand forecast for South Australia against ElectraNet's aggregate connection point forecast. The AER will consider AEMO's findings in making its final transmission determination. The AER, in the meantime, has used its own peak demand forecast to develop the appropriate level of augmentation and connection capital expenditure for this draft decision.

Overall, having considered ElectraNet's revenue proposal, the AER is not satisfied that the proposal is consistent with the NER and the National Electricity Law (NEL). The AER's draft decision on three key elements of the revenue proposal is outlined below. These elements are the demand forecast, capital expenditure and operating expenditure.

Demand forecast

Figure 3 shows ElectraNet's proposed maximum demand forecast and the AER's draft decision.

Figure 3 AER draft decision on ElectraNet's demand forecast



Source: ElectraNet, *Revenue proposal*, appendix J, 2012; EMCa analysis of data supplied by ElectraNet.

Expenditure forecast

Table 1 shows ElectraNet's total capital expenditure and the AER's draft decision. Table 2 shows ElectraNet's total operating expenditure and the AER's draft decision.

Table 1 AER draft decision on ElectraNet's forecast capex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	215.9	186.2	211.4	182.7	97.9	894.1
AER draft decision	183.2	120.3	141.0	122.4	75.0	641.9
Difference	–32.7	–65.9	–70.4	–60.3	–22.9	–252.3

Table 2 AER draft decision on ElectraNet's forecast opex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	88.8	95.8	96.2	98.3	99.0	478.1
AER draft decision	75.0	78.3	79.3	82.0	83.1	397.6
Difference	–13.8	–17.5	–16.9	–16.3	–15.9	–80.5

Next steps

ElectraNet has the opportunity to address this draft decision by submitting a revised revenue proposal by 16 January 2013.

The AER invites submissions from interested parties in response to the draft decision and ElectraNet's revised revenue proposal. The closing date for submissions is 19 February 2013. Further information on providing a submission can be found at http://www.aer.gov.au/node/16617.

Once the AER has considered submissions and ElectraNet's revised revenue proposal, it will publish its final decision in April 2013.

1 About the review

The AER is responsible for regulating the revenues of transmission network service providers (TNSPs) operating in the National Electricity Market (NEM). The National Electricity Law (NEL) and the National Electricity Rules (NER) provide the overarching framework under which the AER operates. In particular, Chapter 6A of the NER provides for the economic regulation of TNSPs. ElectraNet, as a TNSP operating in the NEM, is subject to full regulation by the AER. This means the AER must make a transmission determination for ElectraNet every five years to determine how much revenue ElectraNet can recover from its customers. This draft decision specifies the amendments that the AER considers are necessary for ElectraNet's revenue proposal to meet the requirements under the NEL and NER.

1.1 Overview of ElectraNet

ElectraNet operates a network comprising 5600 kilometres of high voltage electricity transmission lines in South Australia. Its customers include SA Power Networks (the distribution network service provider in South Australia previously known as ETSA Utilities), generators and direct connect customers.[2] Figure 4 shows ElectraNet's electricity transmission network.

Figure 4 ElectraNet's electricity transmission network

Source: ElectraNet, *Revenue proposal*, p. 23.

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2 ElectraNet's direct connect customers include large industrial customers and mines.

1.2 National Electricity Law and National Electricity Rules requirements

The NEL contains two overarching principles that the AER must apply when performing its economic regulatory functions or powers. Under section 16(1)(a) of the NEL the AER must act in a manner that will or is likely to contribute to the achievement of the national electricity objective (NEO). The NEO is set out in section 7 of the NEL:

> The objective of this law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest 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.

The AER must also take into account the revenue and pricing principles when exercising its discretion in making a transmission determination.[3] The revenue and pricing principles are set out in section 7A of the NEL. In short, the revenue and pricing principles require a TNSP to be provided with an opportunity to recover at least its efficient costs, while being provided with incentives to promote economic efficiency.

The AER, in undertaking its assessment of ElectraNet's revenue proposal, has reviewed ElectraNet's business and governance practices, including its asset management and maintenance strategies. In doing so, the AER has sought to develop an understanding of how ElectraNet operates and manages its transmission network to inform the AER's draft decision.

1.3 Review process

The review process that the AER undertakes when making a transmission determination is comprised of several stages. These include the consideration of the TNSP's revenue proposal and submissions on the proposal from other stakeholders, making of the draft decision, consideration of a revised revenue proposal, and the making of the final decision and transmission determination. The AER has engaged with ElectraNet and other stakeholders throughout this process. The submissions from stakeholders and expert advice received during the review process are available on the AER website at http://www.aer.gov.au/node/16617.

1.3.1 Submission of revenue proposal and the AER's draft decision

ElectraNet submitted its revenue proposal and proposed pricing methodology in relation to prescribed transmission services to the AER on 31 May 2012. It also submitted its negotiating framework in relation to its negotiated services. The AER conducted a preliminary examination of ElectraNet's revenue proposal, pricing methodology and negotiating framework and published these on 6 July 2012 along with supporting information.[4]

The AER commissioned the following independent consultants:

- Energy Market Consulting associates (EMCa) and Strata Energy Consulting Ltd for advice on technical aspects of ElectraNet's past and forecast expenditure (capex/opex), associated policies and procedures, contingent projects and service standards.
- EMCa and NZIER for advice on ElectraNet's demand forecast.
- Deloitte Access Economics for advice on forecast growth in labour costs.

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3 NEL, clause 16(2)(a)(i).
4 NER, 6A.10.2 and 6A.11.

After considering the revenue proposal, any submissions made in response by stakeholders to the revenue proposal, and any other matters that the AER considers relevant, the AER must make a draft decision.[5] If the AER refuses to accept certain sections, values or amounts in the revenue proposal, then its draft decision must detail the changes required or matters to be addressed before the AER will approve those sections, values or amounts.[6] The AER must publish its draft decision no later than 6 months after receiving the revenue proposal.[7]

1.3.2 Revised revenue proposal and the AER's final decision

If the AER's draft decision requires changes or matters to be addressed, then the TNSP may submit a revised revenue proposal incorporating the substance of any changes and/or addressing the matters raised in the AER's draft decision.[8] It must submit the revised revenue proposal to the AER within 30 working days after the publication of the AER's draft decision.[9]

The AER must invite written submissions on the draft decision once it publishes the draft decision, a notice of the making of the draft decision, and a notice of a predetermination conference. Any person may attend the predetermination conference and make a written submission on the draft decision. The due date for written submissions must not be earlier than 45 business days after the predetermination conference.[10]

After considering submissions made on the draft decision and a revised revenue proposal the AER must make a final decision and transmission determination.[11] The final decisionmust set out the reasons for the decision. The final decision and transmission determination must also be published by the AER,[12] at least two months before the start of the relevant regulatory control period.[13]

1.3.3 Public consultation

Effective consultation with stakeholders is essential to the AER's performance of its regulatory functions. The AER has actively engaged with stakeholders in making this draft decision, including:

- considering all submissions made on ElectraNet's revenue proposal, except for a late submission from ElectraNet made on 30 October 2012.[14]
- hosting a public forum in Adelaide on 23 July 2012 for stakeholders to engage with ElectraNet on its revenue proposal
- having ElectraNet present its revenue proposal to the AER Chairman and board members in June 2012
- engaging with EMCa and ElectraNet in an eight day on–site review of ElectraNet's revenue proposal in June and July 2012, and follow up workshops in September and October 2012. During this process, the AER and EMCa considered over 200 responses to information requested from ElectraNet.

5 NER, clause 6A.12.1.
6 NER, clauses 6A.12.1(c)–(e).
7 NER, clause 6A.12.2.
8 NER, clause 6A.12.3.
9 NER, clause 6A.12.3(a).
10 NER, clause 6A.12.2.
11 NER, clauses 6A.13.3 and 6A.12.4.
12 NER, clause 6A.13.3.
13 NER, clause 6A.13.3.
14 The AER considered submissions from the South Australian Council of Social Service, the Energy Consumers Coalition of South Australia, the Clean Energy Council, the Energy Users Association of Australia, the South Australian Government, TransGrid and Transend.

- involving other stakeholders, including the Australian Energy Market Operator (AEMO), the Essential Services Commission of South Australia (ESCOSA), SA Power Networks and SA Water.

The AER is holding its predetermination conference in Adelaide on 12 December 2012. Submissions on the AER's draft decision and ElectraNet's revised revenue proposal are due by 19 February 2012.[15] Table 3 summarises the key dates in the AER's decision making process.

Table 3 Key dates in the AER's decision making process

Key date in the decision making process	Date
Submission of ElectraNet's revenue proposal to the AER	31 May 2012
ElectraNet revenue proposal published	6 July 2012
Public forum on ElectraNet's revenue proposal	23 July 2012
Submissions on ElectraNet's revenue proposal due	17 August 2012
Release of AER draft decision	30 November 2012
Predetermination conference	12 December 2012
Submission of ElectraNet's revised revenue proposal due	16 January 2013
Submissions on AER draft decision / ElectraNet's revised proposal due	19 February 2013
AER final decision and transmission determination	30 April 2013

1.3.4 Protected information submitted to the AER

The AER is committed to treating protected information received from TNSPs and other stakeholders in accordance with the NEL. The NEL allows the AER to disclose protected information under certain circumstances.[16] For its draft decision, the AER has released, in accordance with the NEL's specified process, a number of documents that were originally identified as protected information.

1.3.5 Structure of decision document

This draft decision is set out as follows:

- Part 1: AER draft decision – the draft decision on ElectraNet's revenue proposal and a summary of the AER's reasons
- Part 2: attachments – a detailed analysis of the components of the draft decision
- Part 3: appendixes – detailed discussion of technical analysis.

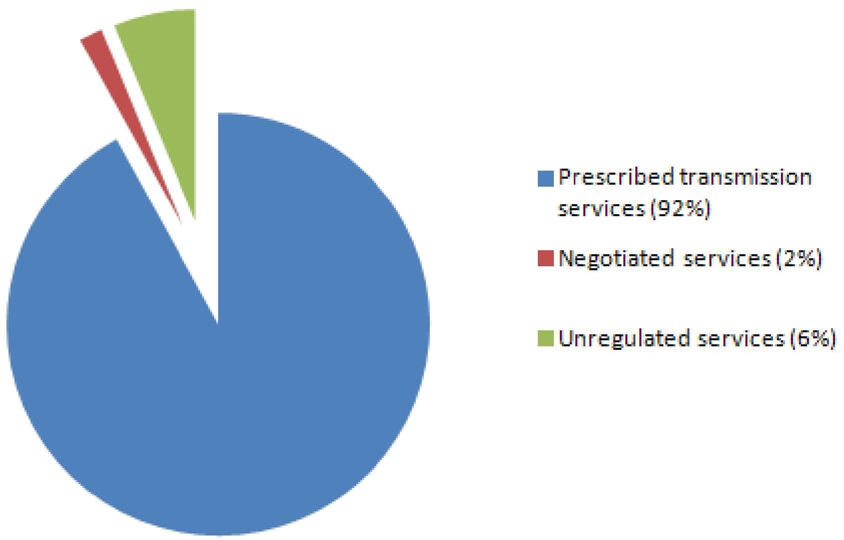
15 Further information on the predetermination conference and how to make a submission can be found at www.aer.gov.au.
16 NEL, Part 3, division 6.

2 AER approach

2.1 ElectraNet's electricity transmission services

ElectraNet's services (comprised of prescribed transmission services, negotiated services and unregulated services) relate to developing, operating and maintaining the South Australian electricity transmission network. Figure 5 shows ElectraNet derives the bulk of its revenue from the provision of prescribed transmission services. The majority of the AER's draft decision concerns assessing the cost of ElectraNet providing prescribed transmission services.

Figure 5 ElectraNet's categories of service by revenue ($2010–11)



Source: ElectraNet, *Regulatory Financial Report 2010–11*, October 2011, p. 5.

The AER regulates prescribed transmission services under a revenue cap. The revenue cap sets the maximum allowed revenue (MAR) that ElectraNet can recover each year through its network tariffs. This revenue recovers the cost of providing prescribed transmission services to customers. ElectraNet's prescribed transmission services comprise:[17]

- the shared transmission service provided to customers directly connected to the transmission network and connected network service providers (prescribed transmission use of system (TUOS) services)
- connection services provided to connect the SA Power Networks' distribution network to the transmission network (prescribed exit services)
- grandfathered connection services provided to generators and customers directly connected to the transmission network that were in place on 9 February 2006 under clause 11.6.11 of the NER (prescribed entry and exit services)
- services required under the NER or in accordance with jurisdictional electricity legislation that are necessary to ensure the integrity of the transmission network. These include the maintenance of power system security and assisting in the planning of the power system (prescribed common transmission services).

[17] ElectraNet, *Revenue proposal*, p. 12.

Unlike prescribed transmission services, the AER does not regulate the revenue that ElectraNet can earn from negotiated transmission services. The NER sets out the type of services that are classified as negotiated transmission services.[18] The NER requires the AER to make a determination on ElectraNet's negotiating framework and Negotiated Transmission Service Criteria (NTSC).[19] These two instruments facilitate the agreement of terms and conditions for the provision of negotiated transmission services between ElectraNet and the customer. The AER's detailed reasons for its draft decision on ElectraNet's negotiated transmission services are provided in attachment 15.

Unregulated services provided by ElectraNet sit outside the jurisdiction of the AER and are not part of the AER's determination.

2.2 Maximum allowed revenue

ElectraNet recovers revenue from its customers via its network tariffs. Its pricing methodology, discussed in section 14 and attachment 14, prescribes the way it recovers this revenue. To determine ElectraNet's revenue for the 2013–18 regulatory control period, the AER assesses the total revenue required by ElectraNet to provide prescribed transmission services for each year of the 2013–18 regulatory control period. This annual revenue requirement reflects the efficient costs of providing prescribed transmission services across the South Australian electricity transmission network.

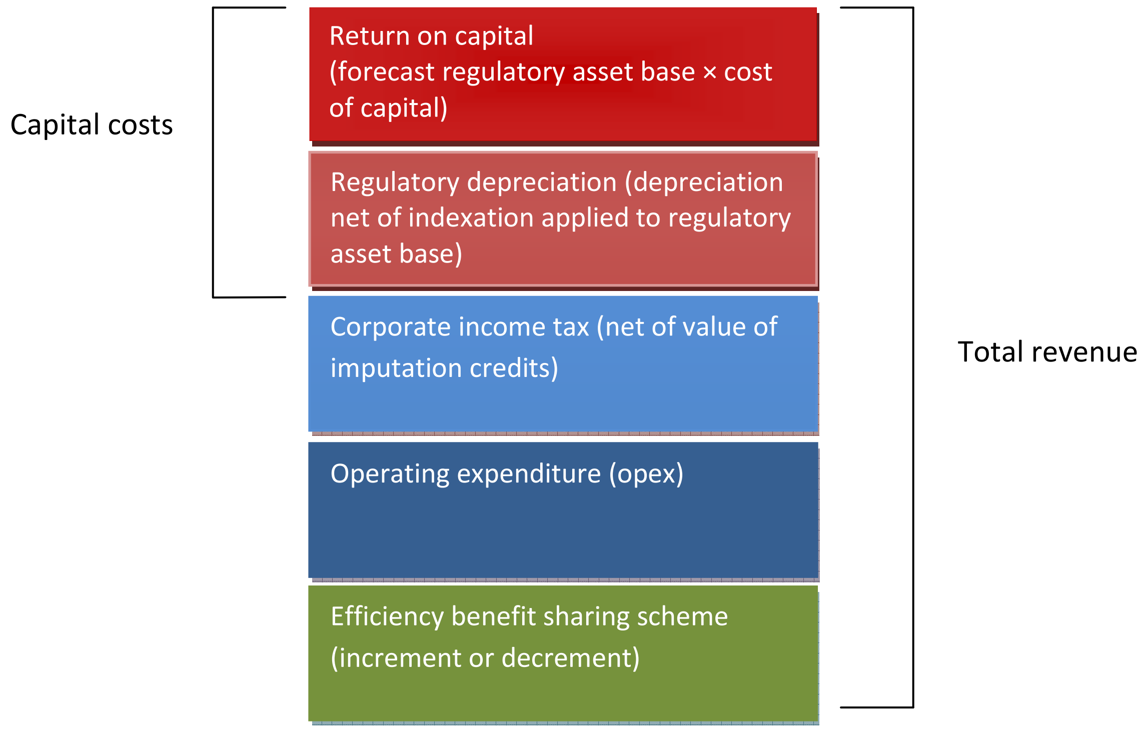
The AER uses the building block approach, as required by the NER, to determine the annual revenue requirement. That revenue requirement comprises the following costs related to the provision of prescribed transmission services:[20]

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

[18] NER, Glossary.
[19] NER, clauses 6A.2.2(2) and (3).
[20] NER, clause 6A.5.4(a).

Figure 6 illustrates the building block approach.

Figure 6 The building block approach for determining total revenue



2.3 What the AER considers in reaching its draft decision

The AER made its draft decision on ElectraNet's revenue proposal for the 2013–18 regulatory control period in accordance with the relevant sections of the NEL and NER. It considered whether ElectraNet's forecast capex and opex reflect the efficient costs that a prudent operator requires to meet the NER objectives (set out in section 2.4).[21] In forming its views on whether ElectraNet's capex and opex forecasts are efficient and prudent, the AER took account of the factors listed in the NER.[22]

In reaching its draft decision, the AER:

- analysed ElectraNet's revenue proposal, pricing methodology and negotiating framework and other supporting information
- analysed information provided by ElectraNet during the review process
- considered submissions from interested parties
- considered views expressed at the public forum and other stakeholder engagement meetings
- considered advice and analysis provided by AER commissioned independent experts.

2.4 NER objectives of capex and opex forecasts

The NER sets out the following objectives for ElectraNet's forecasts of total capex and opex:[23]

21 NER, clauses 6A.6.6(c) and 6A.6.7(c).
22 NER, clauses 6A.6.6(e) and 6A.6.7(e).
23 NER, clauses 6A.6.6(a) and 6A.6.7(a)

- meet expected demand
- comply with all applicable regulatory obligations or requirements
- maintain the quality, reliability and security of supply
- maintain the reliability, safety and security of the transmission system.

The AER must determine whether ElectraNet's forecast capex and opex reflect the efficient costs that a prudent operator in ElectraNet's circumstances requires to meet these objectives, based on a realistic expectation of the demand for transmission services and cost inputs.[24]

The AER considers ElectraNet is generally a well governed and efficient TNSP and that its forecast expenditure is targeted at achieving the capex and opex objectives. Nevertheless, the AER is not satisfied that the proposed forecast expenditure reasonably reflects the efficient costs of achieving the capex and opex objectives for a prudent operator in the circumstances of ElectraNet. The AER also considers that ElectraNet's forecast expenditure does not reflect a realistic expectation of demand.

Meeting expected demand

ElectraNet must be able to deliver electricity to its customers and build, operate and maintain its network to manage expected changes in the demand for electricity. To do this, ElectraNet incurs capex, investing in its network to meet peak demand and increases in electricity consumption. ElectraNet also incurs opex to maintain its network to meet expected demand. The capex and opex required by ElectraNet therefore partly depends on the expected level of demand. However, demand drives the capex forecast to a greater degree than the opex forecast. Section 7 and attachment 2 set out the AER's detailed reasons for its draft decision on the demand forecast.

Compliance with regulatory obligations or requirements

ElectraNet is required to meet state and national statutory obligations. The AER considered these obligations when assessing ElectraNet's forecast capex and opex. The most significant obligations are:

- the provision of a safe, reliable and cost effective transmission network in accordance with the NER and ElectraNet's electricity transmission licence
- the requirements of the NEL and NER
- compliance with all relevant state and federal environmental, planning and cultural heritage legislation
- compliance with all statutory workplace health and safety requirements
- compliance with the Electricity Transmission Code (ETC)
- its role as the South Australian Jurisdictional Planning Body.

Providing quality, reliable, secure and safe transmission services

The NER, ElectraNet's transmission licence, the ETC and customer connection agreements establish the required quality, reliability and security of supply of prescribed transmission services to be provided by ElectraNet. ElectraNet's transmission system must also be reliable, safe and secure.

[24] NER, clauses 6A.6.6(c) and 6A.6.7(c)

Among other factors, old, degraded and/or unsafe assets and environmental factors may affect network reliability, safety and security. The AER considered these obligations when assessing ElectraNet's capex and opex forecasts.

ElectraNet is accountable for delivering prescribed transmission services. Nevertheless, the AER's service target performance incentive scheme (STPIS) strengthens the incentive for ElectraNet to improve transmission system reliability to all customers. In conjunction with the efficiency benefit sharing scheme (EBSS – refer section 10.3), it promotes cost savings from operating efficiencies, rather than cost savings from lower service standard performance.

The STPIS will apply to ElectraNet during the 2013–18 regulatory control period. It provides financial incentives for TNSPs to make efficient decisions to maintain and improve network reliability. The AER makes annual adjustments to ElectraNet's revenue that reward or penalise it for its service performance. Whether ElectraNet receives a reward or a penalty depends on how it performed in relation to its service performance targets. The AER considers ElectraNet's overall service performance has been at a high level. Its draft decision on the STPIS to apply to ElectraNet in the 2013–18 regulatory control period will maintain that performance and promote improvements when they are reasonably achievable. The AER's reasons for its draft decision on ElectraNet's STPIS are provided in section 13 and attachment 11.

ElectraNet proposed a significant increase in its opex and replacement / refurbishment capex. Much of this expenditure is driven by needs identified from ElectraNet's improved asset management framework. Amongst other things, the AER has considered the replacement capex and forecast opex required by ElectraNet to maintain the quality, reliability and security of supply.

ElectraNet's significant increase in its opex and replacement capex is partly aimed at maintaining the reliability and safety of the transmission system. ElectraNet also included security/compliance capex of $57.3 million over the 2013–18 regulatory control period. This capex is associated with addressing compliance with relevant government Acts, regulations and standards and ensuring the security of critical infrastructure assets.[25]

[25] ElectraNet, *Revenue proposal*, p. 58.

3 Total revenue requirements and the impact on price

ElectraNet's total revenue is the AER's forecast of the efficient costs of providing prescribed transmission services. The total revenue cap set out in this draft decision has been determined by assessing the elements of ElectraNet's revenue proposal. That is, the proposed building blocks have been assessed to ensure they reflect the efficient costs of providing prescribed transmission services in South Australia. The revenue requirement of each building block is set out in this section. This section also includes a summary of the likely impact of this draft decision on average electricity prices for consumers.

3.1 Draft decision

The AER's draft decision on ElectraNet's total revenue cap over the 2013–18 regulatory control period is $1507.3 million ($nominal). Table 4 shows the AER's draft decision on ElectraNet's building blocks and total revenue. Each building block is discussed in detail in the attachments to this draft decision.

Table 4 AER draft decision on ElectraNet's proposed revenue requirements ($ nominal)

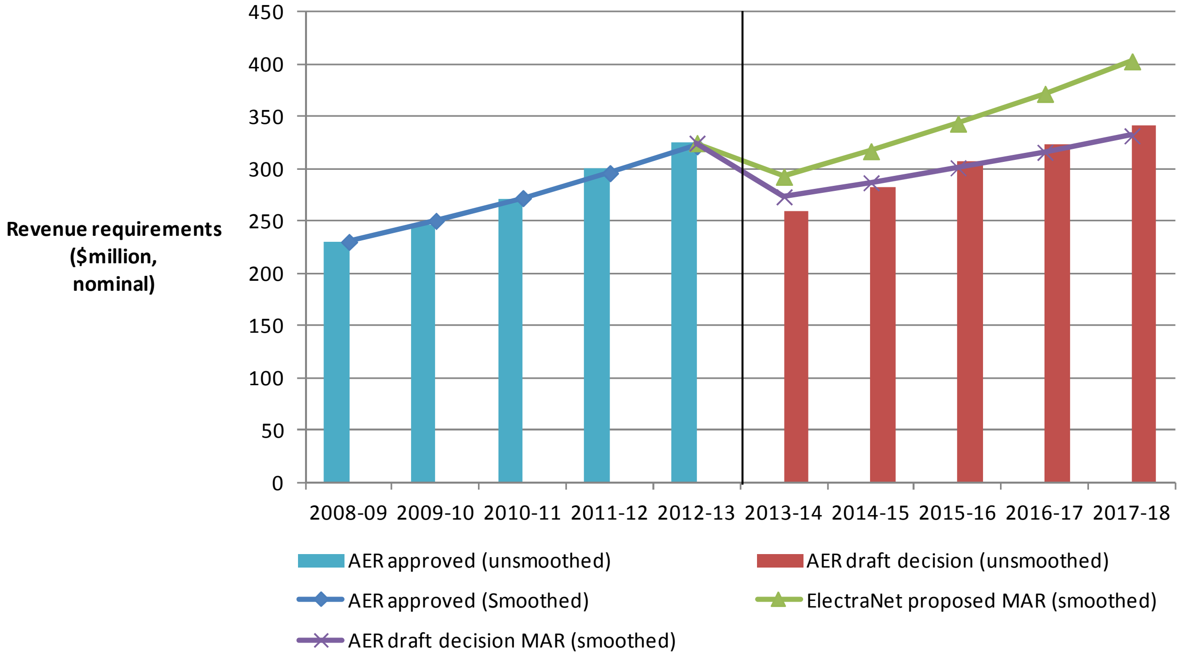
	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Return on capital	147.8	159.3	166.0	173.6	179.9	826.6
Regulatory depreciation [a]	32.6	37.5	49.7	52.0	56.2	228.1
Operating expenditure	77.8	83.2	86.5	91.6	95.2	434.3
Efficiency benefit sharing scheme (carryover amounts)	–3.9	–3.9	–1.6	0	5.1	–4.3
Net tax allowance	4.8	5.1	5.4	6.2	5.2	26.8
Annual building block revenue requirement (unsmoothed)	259.2	281.3	306.0	323.5	341.5	1511.5
Annual expected MAR (smoothed)	273.0	286.5	300.8	315.7	331.3	1507.3
X factor (%)	n/a	–2.4	–2.4	–2.4	–2.4	n/a

Source: AER analysis
(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
(b) The estimated total revenue cap is equal to the total annual expected MAR.

(c) ElectraNet is not required to apply an X factor for 2013–14 because the MAR is set in this draft decision. The MAR for 2013–14 is around 13.0 per cent lower than the MAR in the final year of the 2008–13 regulatory control period (2012–13) in real terms, or 15.9 per cent lower in nominal terms.The AER's draft decision on ElectraNet's total revenue cap (smoothed revenue) is 12.7 per cent less than that proposed by ElectraNet in its revenue proposal. The key elements of the AER's draft decision that reduced ElectraNet's proposed revenue are the capital expenditure (capex) and operating expenditure (opex) allowances.

Figure 11 compares ElectraNet's proposal and the AER's draft decision for revenues over the 2013–18 regulatory control period with the revenue approved by the AER for the 2008–13 regulatory control period. ElectraNet's proposed total smoothed revenue for the 2013–18 regulatory control period is 26.1 per cent higher than the AER allowed total smoothed revenue for the 2008–13 regulatory control period (in nominal dollar terms). The AER's draft decision smoothed revenue for the 2013–18 regulatory control period is 10.1 per cent higher than that approved for the 2008–13 regulatory control period.

Figure 7 AER's draft decision compared to ElectraNet's proposed revenue requirement and approved revenue for 2008–13 ($million, nominal)

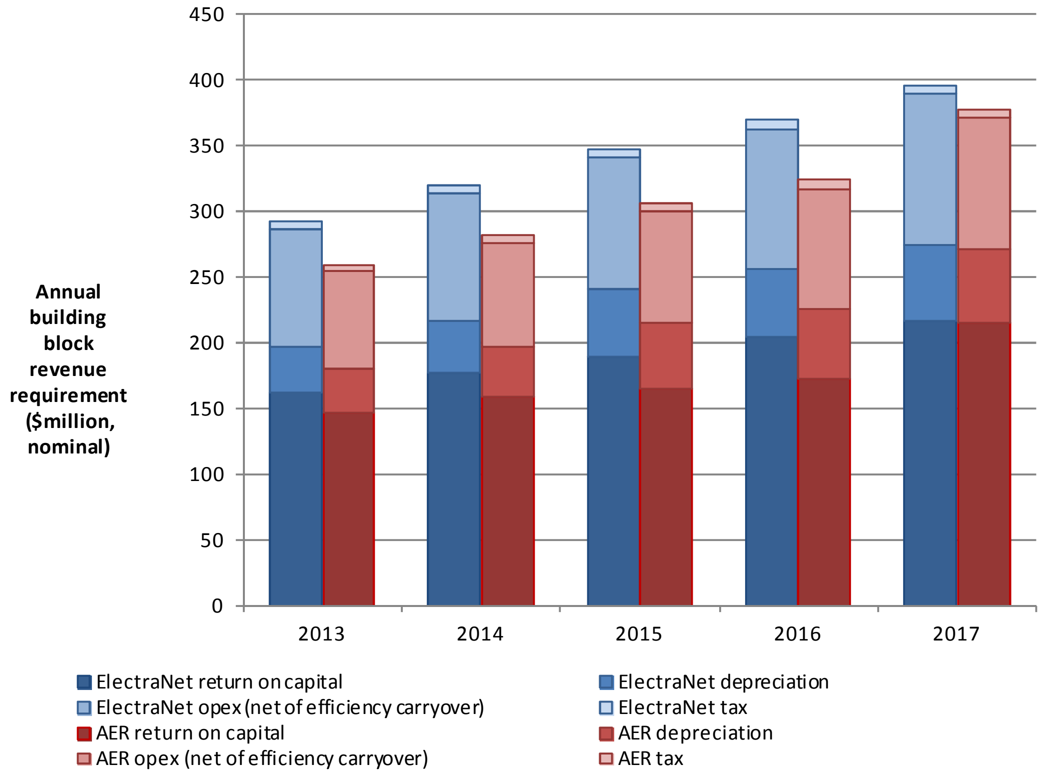


Source: ElectraNet, *Proposed PTRM*, ENET077, May 2012; AER, *PTRM for ElectraNet for the 2008–13 regulatory control period (including contingent projects), 11 February 2011*; AER analysis.

The total revenue is derived by smoothing the annual building block revenue requirements for the 2013–18 regulatory control period. Revenue smoothing helps to reduce fluctuations in the final price that customers pay for electricity.

Figure 8 shows the effect of the AER's draft decision adjustments on ElectraNet's proposed building blocks. This figure shows that the AER's draft decision will reduce ElectraNet's proposals for the return on capital, regulatory depreciation, opex and tax building blocks.

Figure 8 **AER's draft decision and ElectraNet's proposed annual building block revenue requirement (unsmoothed) ($million, nominal)**



Source: ElectraNet, *Proposed PTRM*, ENET077, May 2012; AER analysis.

3.2 Sensitivity analysis

The AER assessed the impact of key aspects of the AER's draft decision on ElectraNet's proposed revenue. These include the AER's draft decision on forecast opex, forecast capex and the cost of capital. The AER's draft decision on each is:

- capex of $641.9 million ($2012–13), compared to ElectraNet's proposed $894.1 million ($2012–13) [26]; a reduction of 28.2 per cent.
- opex (net of EBSS carryover) of $393.2 million ($2012–13), compared to ElectraNet's proposed $465.9 million ($2012–13)[27]; a reduction of 15.6 per cent.
- a cost of capital of 7.11 per cent, compared to ElectraNet's proposed 7.73 per cent.

Table 5 shows that total unsmoothed revenue would be $1646.9 million ($ nominal) or 4.5 per cent lower than ElectraNet's proposed total unsmoothed revenue when the AER's draft decision on the cost of capital is adopted. It also shows that total unsmoothed revenue, based on the AER's draft decision on forecast capex, would be $1685.1 million ($ nominal) or 2.3 per cent lower than ElectraNet's proposed revenue. In addition, the total unsmoothed revenue would be $1645.1 million ($ nominal) or 4.6 per cent lower than the ElectraNet's total proposed revenue, when the AER's draft decision on forecast opex is adopted.

26 Excludes equity raising costs.
27 Net of EBSS carryover amounts.

Table 5 Changes to ElectraNet's total proposed unsmoothed revenue, when AER's draft decision capex forecasts, opex forecast and WACC are adopted

	ElectraNet's proposal ($ million, 2012–13)	AER's draft decision ($ million, 2012–13)	Revenue change ($ million, nominal)	Revenue change (per cent)
Capex[a]	894.1	641.9	-39.3	–2.3
Opex[b]	465.9	393.2	–79.3	–4.6
WACC	7.73 per cent	7.11 per cent	–77.5	–4.5

Source: ElectraNet, *Revenue proposal*, May 2012, pp. 76 and 112; AER analysis.
(a) Excludes equity raising costs.
(b) Includes EBSS carryover amounts.

3.3 Indicative average impact on electricity prices

The AER has calculated an indicative effect of the AER's draft decision on the average South Australian residential customer's electricity bill. To calculate the effect of the AER's draft decision on average transmission charges in South Australia, the AER has:

- taken the sum of ElectraNet's annual expected MAR and the proportion of Murraylink's annual expected MAR that is allocated to South Australian customers (45 per cent),[28] and
- divided it by the forecast annual energy delivered in South Australia.[29]

Based on this approach, the AER estimates that its draft decision will result in a small decrease of 0.1 per cent per annum ($ nominal) in average transmission charges from 2012–13 to 2017–18. In comparison, if ElectraNet's revenue proposal had been accepted in full, average transmission charges would have increased by 3.7 per cent per annum.[30]

The Essential Services Commission of South Australia (ESCOSA) estimates that transmission charges represent approximately 8 per cent on average of a typical customer's electricity bill in South Australia.[31] The AER's draft decision is not expected to contribute towards any price increases for the average South Australian residential and non-residential electricity customers' bills of $1800 and $3457 respectively ($nominal, excluding GST).[32] In comparison, ElectraNet's and Murraylink's proposals would result in the average residential and non-residential bill increases in total over the 2013–18 regulatory control period of approximately $26 and $51 ($ nominal), respectively.

28 Murraylink, *Pricing methodology*, May 2012, p. 3.
29 AEMO, *National electricity forecasting report*, 2012, table 6-1, Medium (Scenario 3, planning).
30 Based on AEMO 2012 energy forecasts. AEMO, *National electricity forecasting report*, 2012, table 6-1, Medium (Scenario 3, planning).
31 ESCOSA, *Email response to information request to the AER*, Enquiry regarding average electricity bills, 17 October 2012.
32 Based on a residential customer consuming approximately 5,000 KWh pa and a small business customer consuming approximately 10,000 KWh pa; ESCOSA, *1 July 2012 Electricity standing contract price adjustment*, June 2012, p. 2; ESCOSA, *Email response to information request to the AER*, Enquiry regarding average electricity bills, 17 October 2012.

4 Regulatory asset base

The regulatory asset base (RAB) is the value of ElectraNet's assets that are used to provide prescribed transmission services. This includes transmission lines, substations, IT systems, land and easement, motor vehicles and buildings. The RAB is the value on which ElectraNet earns a return on capital. Further, ElectraNet is allowed to earn a depreciation allowance (or a return of capital) on assets in its RAB. Hence, the RAB is an important input to the return on capital and depreciation building blocks and consequently, the revenue requirement.

As part of this draft decision, the AER is required to assess ElectraNet's proposed opening value for the RAB for each year of the 2008–13 and 2013–18 regulatory control periods. This involves the AER:

- rolling forward the opening RAB at 1 July 2008 to determine the closing RAB at 30 June 2013.[33] This involves, for each year:
  - adding an inflation (indexation) adjustment for the relevant year[34]
  - adding capex incurred for the relevant regulatory year[35]
  - subtracting actual depreciation for the relevant year[36]
  - subtracting any disposed assets for the relevant year.[37]
- using the AER's draft decision on forecast depreciation, capex, disposals and inflation for the 2013–18 regulatory control period to roll forward ElectraNet's forecast RAB for each year of that period. In particular, forecast capex is added to the RAB while forecast depreciation and disposals are removed from the RAB. Forecast inflation is used to index the resulting RAB.

Following this process, the AER's draft decision includes a value for ElectraNet's opening RAB at 1 July 2013 and a forecast closing RAB at 30 June 2018. The full draft decision and the AER's detailed reasons and analysis on the RAB can be found in attachment 7.

4.1 Draft decision

The AER does not accept ElectraNet's proposed opening RAB of $2099.9 million as at 1 July 2013, because it considers that some of ElectraNet's inputs into the asset base roll forward model (RFM) do not comply with the NER.[38] These include:

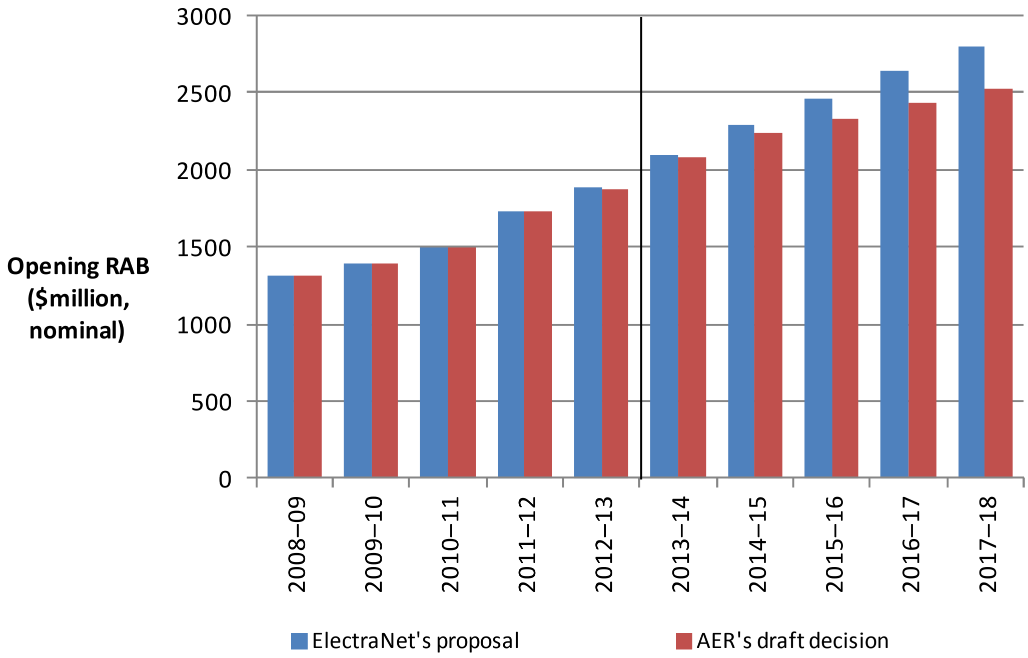
- ElectraNet's proposed opening RAB at 1 July 2008 for the 'Substation primary plant' and the 'Accelerated depreciation' asset classes
- ElectraNet's proposed actual and estimated capex for the 2008–13 regulatory control period
- ElectraNet's proposed 2006–07 actual inflation and 2007–08 nominal WACC inputs.

After adjusting these inputs, the AER has determined an opening RAB value of $2077.8 million ($nominal) at 1 July 2013. This is $22.1 million less than ElectraNet's proposal. Figure 9 shows

33 This closing RAB value is also used as the value of the opening RAB as at 1 July 2013 for the 2013–18 regulatory control period.
34 NER, clause 6A.6.1(e)(3).
35 NER, clause S6A.2.1(f)(4).
36 NER, clause S6A.2.1(f)(5).
37 NER, clause S6A.2.1(f)(6).
38 NER, clause S6A.2.1(f).

ElectraNet's actual opening RAB values for the 2008–13 regulatory control period compared to forecast values for 2013–18 regulatory control period.

Figure 9 ElectraNet's opening RAB over the 2008–13 and 2013–18 regulatory control period ($ million, nominal)



Source: ElectraNet, *Proposed RFM, ENET041*, May 2012; ElectraNet, *Proposed PTRM, ENET077*, May 2012; AER analysis.

Table 6 sets out the AER's draft decision on the roll forward of ElectraNet's RAB during the 2008–13 regulatory control period and the opening RAB at the start of the 2013–18 regulatory control period.

Table 6 **AER's draft decision on ElectraNet's RAB for the 2008–13 regulatory control period ($ million, nominal)**

	2008–09	2009–10	2010–11	2011–12[a]	2012–13[b]
Opening RAB	1311.8	1390.6	1493.6	1723.9	1872.9
Capital expenditure [c]	101.5	122.8	243.9	188.5	229.4
CPI indexation on opening RAB	32.4	40.2	49.8	27.3	56.2
Straight-line depreciation [d]	–55.0	–60.0	–63.3	–66.7	–74.0
Closing RAB as at 30 June	1390.7	1493.6	1723.9	1872.9	2084.5
Difference between forecast and actual capex (1 July 2007 to 30 June 2008)					–0.4
Return on difference for 2007–08 capex					–0.2
Difference between forecast and actual assets under construction (2007–08)					–3.7
Return on difference for 2007–08 assets under construction					–2.5
Opening RAB as at 1 July 2013					2077.8

Source: AER analysis
(a) Based on estimated capex. The AER will update the asset base roll forward for actual capex at the time of its final decision.
(b) Based on estimated capex and forecast inflation. The AER will update the asset base roll forward for actual CPI at the time of its final decision. However, it will update for actual capex at the next reset.
(c) As incurred, net of disposals, and adjusted for actual CPI and weighted average cost of capital (WACC).
(d) Adjusted for actual CPI. Based on as-commissioned capex.

Based on the approved opening RAB and the AER's assessment of forecast capex, depreciation, and inflation, the AER has determined a forecast closing RAB of $2560.0 million ($ nominal) at 30 June 2018. Table 7 sets out the forecast roll forward of the RAB over the 2013–18 regulatory control period.

Table 7 AER's draft decision on ElectraNet's RAB for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18
Opening RAB	2077.8	2239.8	2333.1	2440.6	2528.4
Capital expenditure [a]	194.6	130.8	157.2	139.8	87.8
Inflation indexation on opening RAB	51.9	56.0	58.3	61.0	63.2
Straight-line depreciation [b]	–84.6	–93.5	–108.0	–113.1	–119.4
Closing RAB	2239.8	2333.1	2440.6	2528.4	2560.0

(a) As incurred, and net of disposals. In accordance with the timing assumptions of the PTRM, the capex includes a half-WACC allowance to compensate for the six months period before capex is added to the RAB for revenue modelling purposes.

(b) Based on as-commissioned capex.

4.2 Summary of analysis and reasons

The AER accepts some aspects of ElectraNet's proposal to determine the opening RAB at 1 July 2013. These include:

- ElectraNet's proposed standard and remaining asset lives for actual depreciation purposes, because they are consistent with the approved values for the 2008–13 regulatory control period.
- ElectraNet's proposed total opening RAB as at 1 July 2008 of $1311.8 million ($ nominal), because this total value is consistent with the approved opening RAB at 1 July 2008 set by the Australian Competition Tribunal.[39]

However, the AER considers a number of ElectraNet's proposed inputs into the RFM overstate the value of the opening RAB at 1 July 2013 and consequently, the forecast closing RAB at 30 June 2018. In particular, the AER does not agree with ElectraNet's approach in the following areas:

- ElectraNet's proposed opening RAB at 1 July 2008 for the 'Substation primary plant' and the 'Accelerated depreciation' asset classes are inconsistent with the values in the approved post-tax revenue model (PTRM) for the 2008–13 regulatory control period. The AER amended these values in the proposed RFM so they are consistent with the approved values.
- ElectraNet's proposed actual capex for 2007–08 to 2012–13 included capitalised provisions. The AER considers capitalised provisions should not be included in the RAB as capex, because ElectraNet has not yet paid out (incurred) the expenses to which the provisions relate.
- ElectraNet’s proposed RFM included an incorrect inflation input for 2006–07 and therefore overstates the opening RAB at 1 July 2013.
- ElectraNet’s proposed RFM included incorrect 2007–08 nominal WACC input and therefore overstates the opening RAB at 1 July 2013.
- ElectraNet's proposed forecast capex and depreciation inputs used to roll forward the forecast RAB for the 2013–18 regulatory control period need to be amended in the PTRM. The AER's

39 AER, *Statement on updates for ElectraNet transmission determination 2008–13*, February 2009, p. 1.

assessment of ElectraNet's forecast capex and depreciation inputs are discussed in attachments 4 and 8 respectively.

These adjustments add up to a $22.1 million reduction to ElectraNet's proposed opening RAB at 1 July 2013. The AER's draft decision is an opening RAB of $2077.8 million ($ nominal) at 1 July 2013. Based on this, and the AER's draft decision on forecast capex, depreciation, and inflation, the AER has determined a forecast closing RAB of $2560.0 million ($ nominal) at 30 June 2018.

5 Return on capital

As part of making a determination on the annual building block revenue requirement for a TNSP, the AER is required to make a decision on the return on capital building block.[40] The return on capital building block is calculated as the product of the cost of capital (or rate of rerturn) and the value of the RAB. The AER's draft decision on ElectraNet's RAB is set out in section 4 and attachment 7. This section discusses the cost of capital element of the return on capital building block.

Consistent with the NER the cost of capital is measured as the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the transmission business.[41]

Attachment 6 sets out the AER's detailed reasons for its draft decision on the cost of capital.

5.1 Draft decision

The AER accepts ElectraNet's proposed method for determining the weighted average cost of capital (WACC), including ElectraNet's proposed averaging period.[42] The AER, however, determined an indicative WACC of 7.11 per cent based on more recent market data.

ElectraNet's proposed rate of 7.73 per cent is based on market data from May 2012. The AER's draft decision rate of 7.11 per cent is based on market data from September–October 2012. ElectraNet's proposed rate of return method, if also applied to market data from September–October 2012, would result in a proposed rate of 7.14 per cent. Both ElectraNet's proposed rate of return method, and the AER's method in this draft decision, will be updated using market data for the risk free rate and debt risk premium (DRP) closer to the time of the final decision.

The AER considers a 7.11 per cent rate of return provides ElectraNet with a reasonable opportunity to recover at least the efficient costs of capital financing. Consequently, the AER expects ElectraNet will be able to attract funds to support the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.

Specifically, the AER agrees with the following aspects of ElectraNet's proposed rate of return method:

- applying the capital asset pricing model (CAPM) to determine the return on equity
- adopting the parameter values, methods and credit rating determined in the 2009 WACC review, including:
  - the yield on 10 year Commonwealth Government Securities (CGS) as the proxy for the risk free rate
  - an equity beta of 0.8
  - a MRP of 6.5 per cent
  - a gearing level of 60 per cent

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[40] NER, clause 6A.5.4(a)(2).

[41] NER, clause 6A.6.2(b).

[42] Consistent with the NER, ElectraNet's proposed averaging period will remain confidential until the expiration of the agreed period.

    - an assumed level of imputation credits of 0.65
    - a credit rating of BBB+
- determining the risk free rate over a short averaging period as close as practically possible to the start of the regulatory control period[43]
- specifying the cost of debt as the debt risk premium over the risk free rate
- determining the debt risk premium by defining the benchmark bond as a 10 year Australian corporate bond with a BBB+ credit rating, and measuring the benchmark bond rate using the extrapolated Bloomberg BBB rated seven year fair value curve
- extrapolating the Bloomberg BBB rated seven year fair value curve to a 10 year maturity (consistent with the definition of the benchmark bond) using paired bond analysis[44]
- determining the inflation forecasts based on short term Reserve Bank of Australia (RBA) forecasts and the mid-point of the RBA's inflation targeting band.

Table 8 sets out the individual WACC parameters and subsequent (indicative) rate of return determined by the AER.

Table 8 AER's draft decision on WACC parameters

Parameter	ElectraNet proposal	AER draft decision
Nominal risk free rate	3.26%	3.03%
Equity beta	0.8	0.8
Market risk premium	6.50%	6.50%
Debt risk premium	3.98%	3.34%
Gearing level	60%	60%
Inflation forecast	2.5%	2.5%
Gamma	0.65	0.65
Nominal post tax cost of equity	8.46%	8.23%
Nominal pre tax cost of debt	7.24%	6.37%
Nominal vanilla WACC	7.73%	7.11%

Source: AER analysis and ElectraNet, *Revenue proposal*, p. 129.

5.2 Summary of analysis and reasons

In forming this draft decision, the AER has considered a range of material on the rate of return. This includes ElectraNet's revenue proposal, and submissions into this decision from the Energy Consumers Coalition of South Australia (ECCSA) and the Energy Users Association of Australia (EUAA).

43 As noted previously, ElectraNet's proposed averaging period will remain confidential until the expiration of the agreed period.

44 The AER agrees with ElectraNet's proposed paired bonds extrapolation method, including the selection criteria to choose the paired bonds. However, ElectraNet appears to have incorrectly applied the selection criteria in its proposal. Accordingly, the AER has corrected this error in applying ElectraNet's proposed paired bonds extrapolation method.

In this review, ElectraNet proposed to adopt the values, methods and credit rating determined in the WACC review—specifically, the equity beta, the MRP, the level of gearing and the value of the assumed utilisation of imputation credits (gamma).[45] The AER, therefore, accepts ElectraNet's proposed values for these parameters.

Additionally, ElectraNet proposed adopting the extrapolated Bloomberg fair value curve to estimate the DRP. This results in a DRP of 3.41 per cent based on current market data.[46] The ECCSA and the EUAA, however, stated that this approach cannot be demonstrated to produce an efficient outcome.[47]

The AER considers that the Bloomberg fair value curve continues to provide DRP estimates which are higher than other potential approaches—for example, the ERA's bond yield approach.[48] The Bloomberg fair value curve also provides estimates which are high in comparison to recent bond issuances from firms with similar characteristics to the benchmark firm.[49] For these reasons, the AER has commenced an internal review into alternatives to the Bloomberg fair value curve. The AER will advise of a public consultation process, but does not expect to implement any new method in time for ElectraNet's 2013–18 regulatory control period.[50]

In this draft decision, the AER has maintained adoption of the extrapolated Bloomberg BBB fair value curve. This currently provides a DRP of 3.34 per cent or cost of debt of 6.37 per cent.[51] This results in a WACC of 7.11 per cent.

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45 The assumed utilisation of imputation credits (gamma) affects the corporate income tax building block allowance. Although gamma is not directly included in the determination of the WACC, it was determined in the WACC review.

46 This estimate reflects the paired bonds sample proposed by ElectraNet.

47 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application, A response by ECCSA*, August 2012; EUAA, *Submission on ElectraNet's revenue proposal for 2013/14–2017/18*, August 2012.

48 The ERA estimated the DRP by averaging observed bond yields that met certain criteria. See, ERA, *Revised decision, Access arrangement revisions for the Mid-West and South-West Gas Distribution System*, 25 June 2012, pp. 5–12. See, for example: AER, *Access arrangement draft decision, APA GasNet Australia (Operations) Pty Ltd, 2013–17*, September 2012, pp. 72–74.

49 See, for example: AER, *Access arrangement draft decision, APA GasNet Australia (Operations) Pty Ltd, 2013–17*, September 2012, pp. 72–74.

50 This reflects the Tribunal's previous comments on the consultation process that should be adopted in the development of any new approach.

51 This estimate reflects an adjustment to ElectraNet's proposed extrapolation approach. This adjustment is discussed in detail in attachment 6 of this draft decision.

6 Regulatory depreciation

The AER is required to make a decision on ElectraNet's indexation of the regulatory asset base (RAB) and depreciation building blocks over the 2013–18 regulatory control period.[52] The regulatory depreciation allowance (or return of capital) is calculated as:

Regulatory depreciation allowance = straight line depreciation of RAB – indexation of RAB

ElectraNet's proposed regulatory depreciation allowance comprises about 14 per cent of ElectraNet's proposed total revenue.[53]

ElectraNet is required to submit proposed depreciation schedules for its RAB.[54] The depreciation schedule sets out the basis on which the RAB is to be depreciated for the purpose of determining a regulatory depreciation allowance. The AER must assess whether the proposed depreciation schedule complies with the requirements of the NER. These requirements include:[55]

- that the schedules depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets, and
- that the sum of the real value of the depreciation attributable to any asset or category of assets must be equivalent to the value at which that asset or category of assets was first included in the RAB for the relevant transmission system.

The regulatory depreciation allowance is an output of the PTRM. Therefore, the AER has assessed the PTRM inputs used for calculating the regulatory depreciation allowance against the requirements of the NER. These inputs are:

- the opening RAB as at 1 July 2013
- the forecast net capex in the 2013–18 regulatory control period
- the forecast inflation rate for the 2013–18 regulatory control period
- the standard asset life for each asset class – used for calculating the depreciation of new assets associated with forecast net capex in the 2013–18 regulatory control period
- the remaining asset life for each asset class – used for calculating the depreciation of existing assets associated with the opening RAB as at 1 July 2013.

The first three inputs are considered elsewhere in this draft decision. The final two inputs are considered in this section. Attachment 8 sets out the AER's full draft decision and detailed reasons and analysis on regulatory depreciation.

6.1 Draft decision

The AER does not accept ElectraNet's proposed depreciation allowance of $233.6 million ($ nominal) for the 2013–18 regulatory control period. The AER has decreased ElectraNet's proposed regulatory depreciation allowance by $5.5 million ($ nominal) (or 2.4 per cent) to $228.1 million. Table 9 sets out the AER's draft decision on ElectraNet's depreciation allowance.

52 NER, clauses 6A.5.4(a)(1) and (3).
53 ElectraNet, *Revenue proposal*, p. 151.
54 NER, clause S6A.1.3(7).
55 NER, clauses 6A.6.3(b)(1) and (2).

Table 9 AER's draft decision on ElectraNet’s depreciation allowance for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Straight-line depreciation	84.6	93.5	108.0	113.1	119.4	518.6
Less: inflation indexation on opening RAB	51.9	56.0	58.3	61.0	63.2	290.5
Regulatory depreciation	32.6	37.5	49.7	52.0	56.2	228.1

Source: AER analysis.

6.2 Summary of analysis and reasons

The AER accepts ElectraNet’s proposal to use the straight-line method for calculating the regulatory depreciation allowance as set out in the PTRM. However, the AER does not accept ElectraNet's proposed regulatory depreciation allowance of $233.6 million. The AER has decreased this to $228.1 million. This reduction is necessary because:

- the AER does not accept ElectraNet's proposed depreciation schedule for the 'Transmission line refit' asset class. This is because the proposed standard asset life of 15 years does not reflect the economic life of the assets in this asset class.[56] The AER has determined a standard asset life of 27 years, which reflects the weighted average of the economic lives of the assets used for the forecast transmission line refurbishment works.
- the AER has reduced the amounts allocated for accelerated depreciation purposes to $3.6 million from the proposed $5.6 million, due to the AER's adjustment to ElectraNet's proposed replacement capex discussed in attachment 4.
- the AER accepts ElectraNet's proposed weighted average method to calculate the remaining asset lives as at 1 July 2013. In accepting the weighted average method, the AER has updated ElectraNet's remaining asset lives as at 1 July 2013 to reflect the AER's adjustments to the RAB roll forward in the RFM, as discussed in attachment 7.[57]
- the AER’s determinations on other components of ElectraNet’s proposal also affect the regulatory depreciation allowance.[58] Discussed in other attachments, these determinations include the forecast capex (attachment 4) and the opening RAB as at 1 July 2013 (attachment 7).

56 NER, clause 6A.6.3(b)(1).

57 At the time of this draft decision, the roll forward of ElectraNet's tax asset base (TAB) includes estimated capex values for 2011–12 and 2012–13. The AER will update the 2011–12 estimated capex value for its final decision with the actual value. The AER may update the 2012–13 capex value if ElectraNet's revised proposal includes a more up-to-date estimate. The 2011–12 and 2012–13 capex values are used to calculate the weighted average remaining tax asset lives in the RFM. Therefore, the AER will recalculate ElectraNet's remaining tax asset lives as at 1 July 2013 using the method approved in this draft decision to reflect the actual 2011–12 capex (and the 2012–13 capex estimate where relevant) for the final decision.

58 NER, clause 6A.6.3(a)(1).

7 Demand

ElectraNet must be able to deliver electricity to its customers and build, operate and maintain its network to manage expected changes in the demand for electricity. To do this, ElectraNet incurs capex, investing in its network to meet peak demand and increases in electricity consumption. ElectraNet also incurs opex to maintain its network to meet expected demand. The amount of capex and opex required by ElectraNet therefore partly depends on the expected level of demand. However, the demand forecast drives the capex forecast to a greater degree than the opex forecast.

As the demand forecast is an important input for the capex forecast, the AER needs to determine whether the demand forecast is a realistic expectation of demand.[59] The AER's detailed reasons and analysis on ElectraNet's demand forecast can be found in attachment 2.

7.1 Draft decision

The AER considers that ElectraNet's demand forecast is not a realistic expectation of demand. shows the AER's draft decision on ElectraNet's demand forecast for prescribed transmission services during the 2013–18 regulatory control period. The AER's draft decision on ElectraNet's demand forecast reduced ElectraNet's capex forecast by $103.7 million ($2012–13).

Table 10 AER's draft decision on ElectraNet's demand forecast

	2013-14	2014-15	2015-16	2016-17	2017-18
ElectraNet forecast (MW)	4077	4200	4321	4443	4553
AER forecast (MW)	3644	3721	3797	3872	3928
Difference (MW)	433	479	524	571	625
Difference (%)	10.7	11.4	12.1	12.9	13.8

Source: ElectraNet, *Revenue proposal,* appendix J and EMCa analysis.

7.2 Summary of analysis and reasons

7.2.1 Assessment of ElectraNet's demand forecast

The AER considers ElectraNet's demand forecast exceeds a realistic expectation of demand as it is determined from a forecasting method, data set and assumptions that biased the modelling results. In particular the AER considers that the method used to produce ElectraNet's demand forecast:

- did not appropriately consider the uncertainty of temperature fluctuations on peak
- did not appropriately account for photovoltaic generation, embedded generation, and demand response[60]
- did not apply a diversity factor when modelling regional forecasts, which is needed to reflect differences in peak demand across the regions

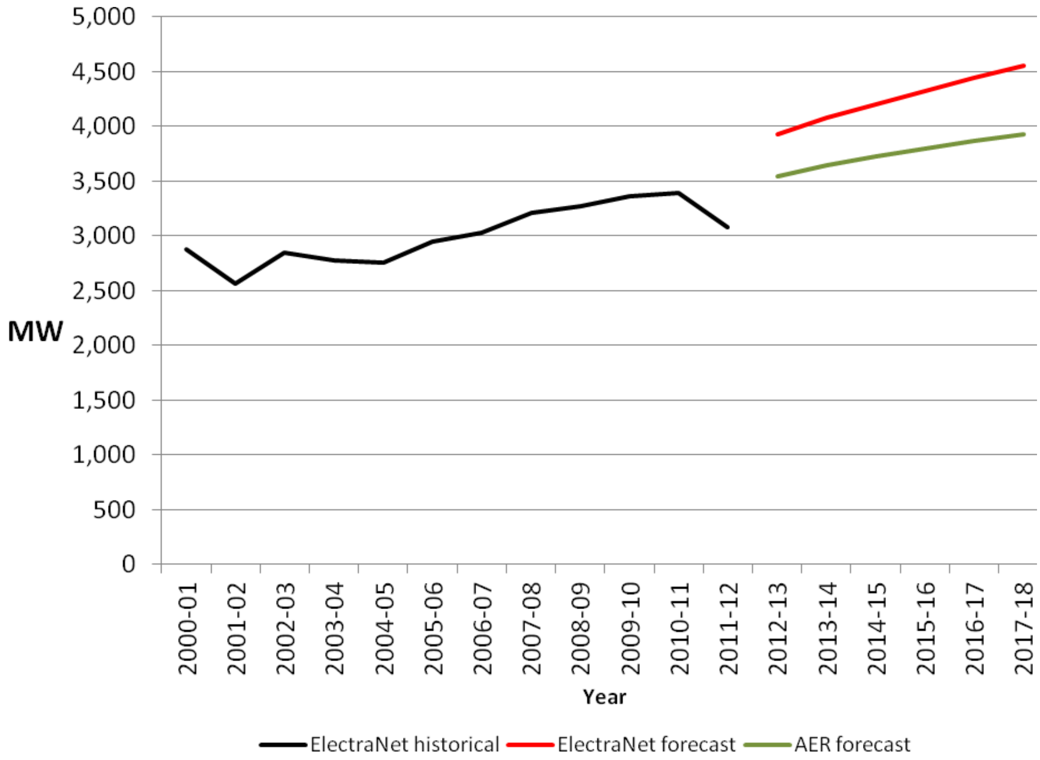
59 NER, clause 6A.6.7(c).
60 Demand side participation is where a customer reduces its energy requirements at times of peak demand, usually by agreement with the TNSP. Embedded generation means electricity that is generated by sources in the network such as household roof top photovoltaic generation.

- was not reconciled to a top down econometric forecast (such as AEMO's 2012 state wide demand forecast).

Both ElectraNet and AEMO are currently working to reconcile ElectraNet's 2012 connection point forecast with AEMO's 2012 top down forecast for South Australia. Neither reconciliation was available for this draft decision. Therefore, the AER has used a linear trend forecast developed by EMCa as its substitute. On the information currently before it, the AER considers EMCa's forecast is a realistic expectation of demand for the purposes of forecasting capex. The lower demand forecast has the effect of reducing capex by $103.7 million ($2012–13).

Figure 10 shows the difference between ElectraNet's demand forecast and EMCa's demand forecast

Figure 10 Difference between ElectraNet's demand forecast and AER's demand forecast



Source: ElectraNet, *Revenue proposal*, appendix J, 2012; ElectraNet, *Summary CP historical and forecast peaks*, ENET0063, June 2012 [confidential]; ElectraNet, *Response to EMCa041 - Peak Load Data (Revised)*, ENET244, 29 August 2012 [confidential]; EMCa analysis of data supplied by ElectraNet.

7.2.2 The South Australian Electricity Transmission Code

ElectraNet submitted that it must accept SA Power Networks' demand forecast 'as is' because it is obliged to do so under the South Australian Electricity Transmission Code (ETC).[61] The AER considers this position is incorrect.

- The AER considers that ElectraNet's obligation under the ETC is to react to a change in 'forecast agreed maximum demand' (FAMD).[62] This obligation is not an obligation to accept FAMD as presented to it by SA Power Networks.

[61] ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, p. 4.
[62] ETC, TC/07, clause 2.11, p. 8, effective 1 July 2013.

- The AER considers that ElectraNet's obligations under the ETC are regulatory obligations but they are not 'applicable regulatory obligations' under the NER capex objectives. The obligations under the ETC are for planning purposes to avoid anticipated breaches of the ETC reliability standards. The obligation under the NER is to develop a demand forecast to drive a total forecast capex for the purposes of a revenue determination.
- There is no obligation in the ETC that requires ElectraNet to develop a demand forecast. FAMD is merely a definition of an agreed level of demand. The AER considers that ElectraNet should negotiate with SA Power Networks to reach such an agreement.

Accordingly, the AER considers that ElectraNet does not have a regulatory obligation under the ETC to accept SA Power Networks' demand forecasts 'as is'. The AER may therefore use a substitute forecast of required capex because it is not satisfied that ElectraNet's total forecast capex for the regulatory control period reasonably reflects the capex criteria.[63]

[63] NER, clause 6A.6.7(c)(3).

8 Forecast expenditure

The AER observes that the increased opex and replacement / refurbishment capex is largely driven by ElectraNet's improved asset management framework. This section sets out the AER's consideration of ElectraNet's improved asset management framework and its implications on forecast opex and capex.[64]

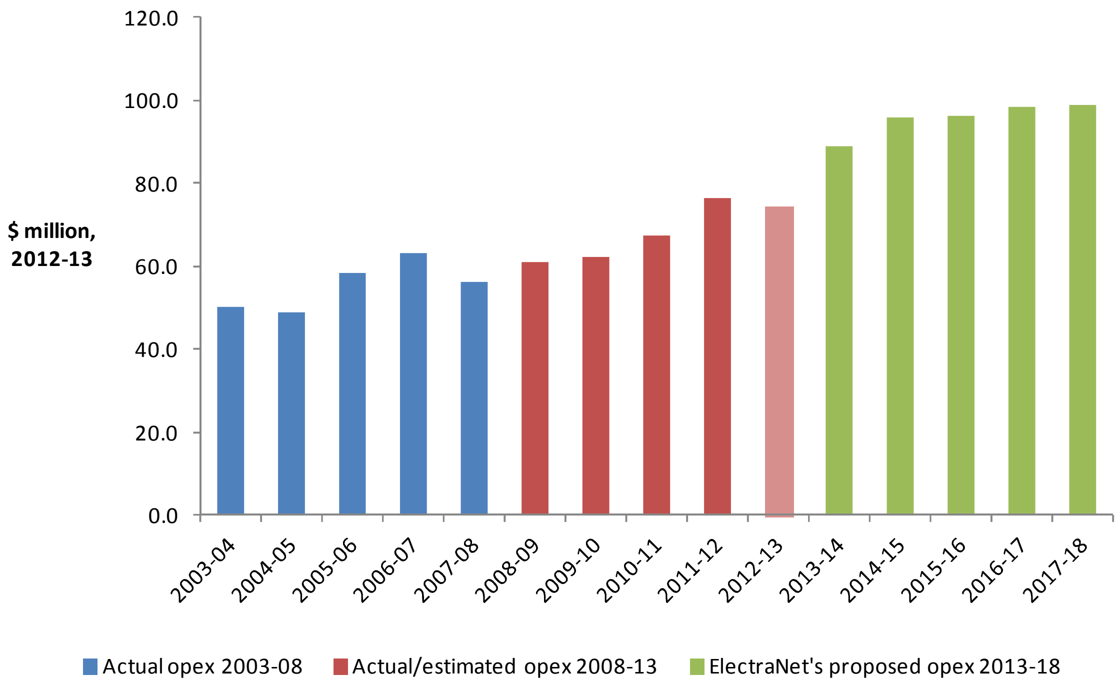
ElectraNet's asset management framework is a condition and risk based total asset life cycle management approach. The AER refers to this as the integrated asset management framework. The AER took into account its findings on this framework in determining the efficient and prudent expenditure allowances. In particular, the AER's substitute opex allowance includes a step change increase to ElectraNet's routine maintenance opex and a capex allowance that accounts for the benefits from implementing this integrated asset management framework (capex / opex trade-off).

ElectraNet's integrated asset management framework is based on:

- comprehensive asset condition intelligence and data
- risk assessment driven work prioritisation
- an optimisation model based on total asset life cycle.

ElectraNet proposed significant replacement / refurbishment capex and opex increases driven by its integrated asset management framework. Figure 11 compares ElectraNet's actual opex with its forecast opex.

Figure 11 ElectraNet's actual and forecast opex

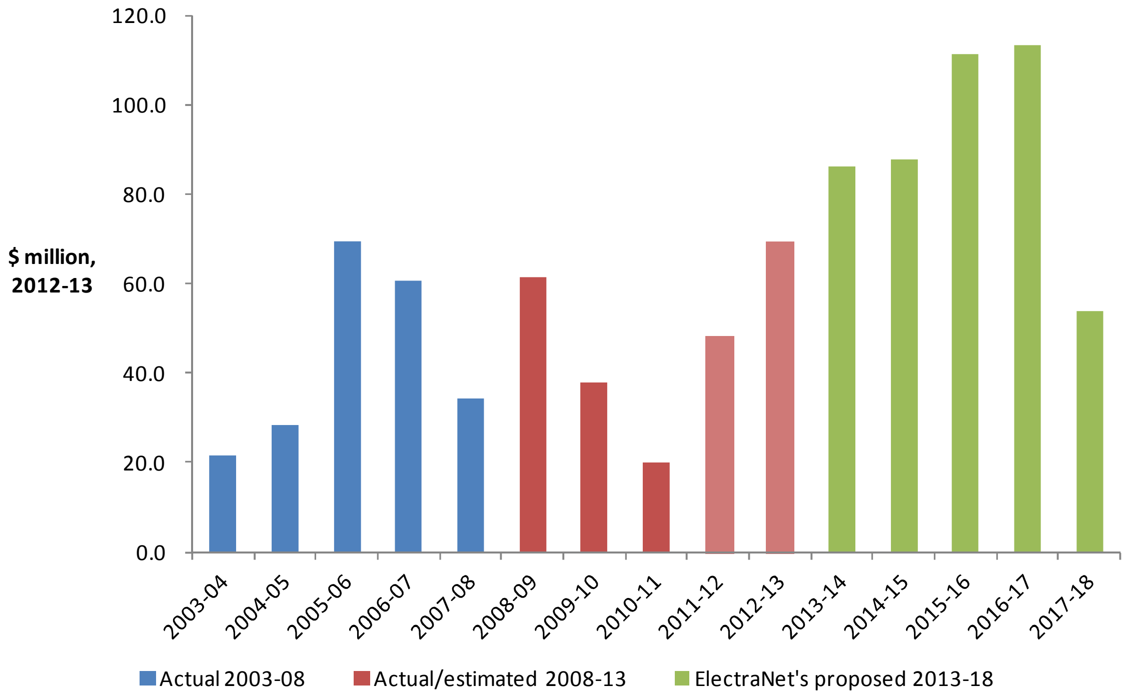


Source: ElectraNet, ENET096, response to information request AER RP 06, *ElectraNet's historic and forecast capex and opex by category in $m 2012–13*, 26 June 2012; ElectraNet, *Annual regulatory financial report 2011-12*.

[64] Opex and capex criteria, NER, clauses 6A.6.6(c) and 6A.6.7(c).

Figure 12 shows ElectraNet's actual and forecast replacement and refurbishment capex.

Figure 12 ElectraNet's actual and forecast replacement / refurbishment capex



Source: ElectraNet, ENET096, response to information request AER RP 06, *ElectraNet's historical and forecast capex and opex by category in $m 2012–13*, 26 June 2012.

The AER's detailed reasons for its draft decision on ElectraNet's integrated asset management framework is provided in attachment 3 (forecast expenditure). These reasons also inform the AER's draft decision on ElectraNet's capex and opex.

8.1 Draft decision

The AER does not consider that ElectraNet's capex and opex forecast sufficiently reflect the economic benefits of its improved asset management framework. The capex and opex forecasts do not meet the capex and opex criteria under the NER. The AER has reduced ElectraNet's capex forecast by $50 million ($2012–13) to account for capex / opex trade-off benefits arising from the implementation of the integrated asset management framework.[65]

8.2 Summary of analysis and reasons

The AER accepts that condition-based maintenance regimes can facilitate lifecycle management of risks in a transparent and cost-effective manner. Such frameworks allow the measurements of trade-offs between expenditure and risks including measuring project level risks for given levels of expenditure. However, the AER is not satisfied that ElectraNet's integrated asset management framework which drives significant expenditure increases, results in efficient expenditure forecast consistent with a prudent operator. As a result, the expenditure proposal is overstated. The key reasons for this finding are:

65 The adjustment for as incurred capex for 2013–18 regulatory control period is approximately $50.1 million ($2012–13).

- ElectraNet's integrated asset management framework design and structure is consistent with good industry practice and the investment in its integrated asset management framework is capable of delivering material benefits to ElectraNet and its customers.
- ElectraNet's high level management decisions have not yet been fully informed by its integrated asset management framework and therefore expenditures have not been adequately justified under its comprehensive governance systems.
- The higher costs incurred by ElectraNet in developing and applying its new system cannot stand alone without considering the benefits that are likely to arise.
- ElectraNet has not assessed the economic benefits of its asset management framework. It has also not assessed the economic benefits of reducing maintenance expenditure by undertaking targeted replacements. Nor has it shown the economic benefits of deferring replacements by increasing opex.
- The AER has approved scope changes to ElectraNet's field maintenance opex category. This has resulted in an opex allowance increase above the revealed cost trend. At the same time, the AER expects that ElectraNet's expanded and improved field maintenance program in combination with its asset management framework ought to lead to lower replacement capex in the future.
- The AER considers that ElectraNet should to be able to defer at least $50 million($2012–13) of replacement / refurbishment capex in the 2013–18 regulatory control period. The AER has therefore made a capex/opex trade off adjustment. The AER considers that increased opex (due to integrated asset management framework) and reduced capex (benefits of integrated asset management framework) allowances are interrelated. The higher costs incurred in developing and applying the new system cannot stand alone without considering the benefits that are likely to arise.

In the absence of this capex adjustment, ElectraNet will not only recover the implementation cost of this program but also recover the economic benefits inherent in the capex/opex trade off which it has not accounted for in its expenditure forecast. The AER considers that such an approach is inconsistent with the NEO[66], in that, it does not recognise the long term interests of consumers.

66 NEL. clause 7.

9 Capital expenditure

Forecast capital expenditure (capex) is a forecast of the cost of new assets that are likely to be required by a network business during a regulatory control period for the efficient operation of the network. As well as assessing forecast capex, the AER reviews actual capex undertaken during the previous regulatory control period. The final approved forecast capex is used in conjunction with the opening RAB, rate of return and depreciation to determine the return on capital building block.

ElectraNet's capex is either network or non–network capex. ElectraNet's network capex is divided into load driven and non–load driven capex.[67] Load driven capex is comprised of the following categories:

- augmentation – capex to increase the system or increase the system's capacity to transmit electricity
- connection – capex to either establish new customer connections or to increase the capacity of existing customer connections
- strategic land/easements – strategic land and easement acquisitions for projected augmentation, connection and replacement requirements.

Non–load driven capex is comprised of the following categories:

- replacement – capex to replace transmission lines, substations, communications equipment and other transmission system assets
- refurbishment – capex to replace relevant components of transmission lines to mitigate risk of failure
- security/compliance – capex that addresses compliance with government Acts, regulations and standards
- Inventory/spares – spare holdings required to respond to asset failures in accordance with restoration times specified in the ETC.

ElectraNet also has two non–network related capex categories:

- business IT – capex to develop and maintain IT capacity
- buildings/facilities – capex to replace and upgrade office accommodation.

Factors that influence the required capex include the age and condition of assets, changes in the number of customers connected to the network, changes in the demand for electricity transmission services and general 'business as usual' capex requirements.

The AER assesses capex forecasts against the requirements of the NER. The AER must accept the capex forecast if it is satisfied that it reasonably reflects:

- the efficient costs to achieve the capex objectives, which are:[68]
  - meet the expected demand for prescribed transmission services over the regulatory control period

[67] ElectraNet, *Revenue proposal*, pp. 57–58.
[68] NER, clause 6A.6.7(a).

- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services
- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

- the costs that a prudent operator in the circumstances of ElectraNet would require to achieve the capex objectives;[69] and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.[70]

If the AER is not satisfied that the forecast capex reflects the above criteria, then it must not accept the forecast capex, and must determine a substitute forecast capex.[71]

In assessing ElectraNet's proposed capex forecast, the AER considered material such as ElectraNet's:

- asset management framework and policies
- business management systems and operations
- strategic planning
- business process improvement initiatives
- investment justification processes
- major identified risks and risk management practices adopted to manage those risks.

The AER also engaged a consultant, EMCa to review ElectraNet's proposed capex forecast. Attachment 4 sets out the AER's detailed reasons for its draft decision on ElectraNet's forecast capex.

9.1 Draft decision

The AER does not accept ElectraNet's proposed capex forecast of $894.1 million ($2012–13) for the 2013–18 regulatory control period. The AER estimated forecast capex of $641.9 million ($2012–13) which represents a reduction of $252.3 million ($2012–13) or 28.2 per cent on ElectraNet's proposal.

Table 11 shows the AER's draft decision on ElectraNet's total forecast capex for the 2013–18 regulatory control period.

69 NER, clause 6A.6.7(c)(2).
70 NER, clause 6A.6.7(c)(3).
71 NER, clauses 6A.6.7(d) and (f).

Table 11 AER draft decision on ElectraNet's forecast capex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	215.9	186.2	211.4	182.7	97.9	894.1
AER draft decision	183.2	120.3	141.0	122.4	75.0	641.9
Difference	32.7	65.9	70.4	60.3	22.9	252.3

Source: AER analysis. Note these figures are the "as incurred" $ million real 2012—13. Numbers may not add due to rounding.

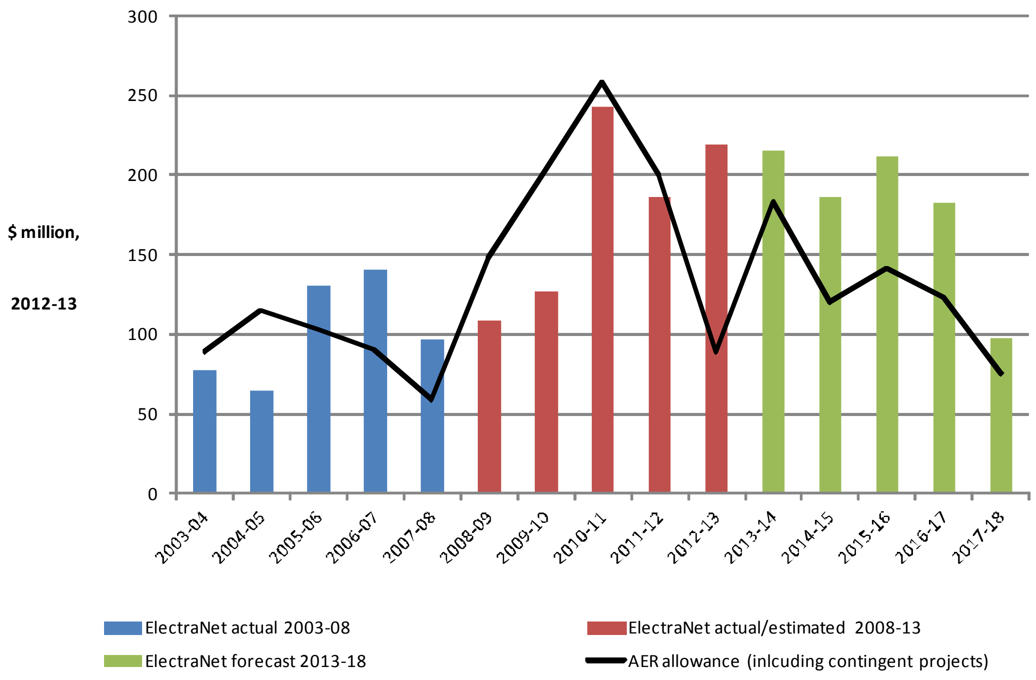
9.2 Summary of analysis and reasons

Overall, the AER does not accept that ElectraNet's proposed total forecast capex satisfies the requirements of the NER and NEO for the reasons outlined in attachments 3 and 4.[72] The AER considers ElectraNet has proposed a forecast significantly above reasonable requirements. That is, ElectraNet has taken an 'overly cautious' approach to developing an efficient and prudent capex forecast. ElectraNet's forecast is based on an unrealistic expectation of demand and a failure to account for its own actions on continuous improvement. Thus, the AER has made adjustments to components of ElectraNet's capex forecast to develop its substitute forecast as required under the NER.[73]

9.2.1 ElectraNet's historical capex

Figure 13 compares ElectraNet's actual, estimated and forecast capex for the two most recent and upcoming regulatory control periods, and the AER's capex allowance.

Figure 13 Comparison of ElectraNet's capex and the AER's allowance ($ million, 2012–13)



Source: AER analysis. The AER allowance only includes contingent projects that were triggered.

72 NER, clause 6A.14.1(2)(ii), NER, clause 6A.6.7(c), NEL, s.7 and s.7A.
73 NER, clause 6A.14.1(2)(ii), NER, clause 6A.6.7(c), NEL, s.7 and s.7A.

The capex profiles in the two preceding regulatory control periods have been significantly different to that approved by the AER. EMCa considered that ElectraNet's capex profile demonstrates that it is able to make prudent and efficient savings at times. However, EMCa also observed that ElectraNet considered the AER approved capex allowance to be a budgetary expenditure allowance which may lead to higher expenditure than necessary. EMCa noted examples where ElectraNet had brought forward expenditure into the 2013–18 regulatory control period to ensure its actual capex was similar to the AER allowance. The AER has considered ElectraNet's historical capex profile, and its ability to incur capex through prudent asset management decisions, when reviewing its forecast capex for the 2013–18 regulatory control period.

9.2.2 ElectraNet's forecast capex

Cost estimation risk factor

The AER does not accept ElectraNet's proposed cost estimation risk factor. The cost estimation risk factor is applied to capital projects that are still in concept stage and yet to undergo detailed cost build–up. It accounts for the risk that unforseen factors will lead actual project costs to exceed initial cost estimates. The AER considers ElectraNet's risk factor does not take account of ElectraNet's investment in more robust cost estimation tools and processes in recent years. The AER also considers that different risk factors should apply to different categories of the capex forecast. This is because replacement and refurbishment capex is more certain than augmentation and connection capex. The AER has substituted multiple risk factors to reflect a realistic expectation of the cost inputs for the different capex categories.

Replacement and refurbishment capex

Prudency adjustments

ElectraNet's capex projects are subject to the Project Management Methodology (PMM). The PMM consists of six progression phases ranging from the concept stage to the complete project scoping. A project must obtain approval during a formal review to progress to the next phase. During each phase, ElectraNet assesses alternative options to decide which option will result in the most efficient outcome. ElectraNet's forecast capex contains many projects that are still in the early stages of development. The AER considers that efficiencies will be found as projects progress through the PMM to implementation.

EMCa reviewed a sample of projects comprising 48 per cent of total network projects. This included replacement and refurbishment projects equal to 43 and 74 per cent of total proposed replacement / refurbishment capex, respectively. EMCa identified expected gains of $11.5 million from its review of the replacement capex projects which equated to 7 per cent of the value of its sample. Based on its findings, EMCa estimated that gains of 7 per cent across replacement / refurbishment capex are likely as projects were developed further and ElectraNet applied prudent decisions.

The AER has applied a reduction of $31.7 million ($2012–13) to ElectraNet's replacement and refurbishment capex forecast.

SA Water asset replacement capex

The AER accepts that the SA Water assets (primarily substations relating to water pumping stations) need to be replaced. However, the AER has concerns that the proposed replacement option may not be the most efficient and prudent option. Due to the 'grandfathering' arrangements in the NER, the

AER has limited scope to make adjustments to ElectraNet's SA Water asset replacement capex. The AER therefore accepts ElectraNet's proposed capex forecast relating to SA Water asset replacement.

Capex/opex trade off

The AER has reduced ElectraNet's proposed replacement capex by $50 million to account for the capex / opex trade off. Section 8 and attachment 3 provides more detail on the AER's considerations on this matter.

Real cost escalation

Real cost escalation is a method of accounting for expected changes in the costs of key input factors such as labour and materials. Due to market forces, these costs may not increase at the same rate as inflation.

Overall, the AER does not accept that ElectraNet's proposed real cost escalation reasonably reflects a realistic expectation of the cost inputs required to achieve the capex and opex objectives.[74] The AER has:

- applied the labour cost forecasts derived by the AER's consultant, Deloitte Access Economics (DAE)
- updated the exchange rates and forecast inputs for material and land value escalators to reflect the most recent data
- applied three land value escalators (residential, commercial and rural) to ElectraNet's land and easements capex, rather than the single land value escalator proposed by ElectraNet.

The application of the AER's draft decision on ElectraNet's real cost escalators affects both capex and opex. Table 12 shows the impact of the AER's draft decision on real cost escalators on ElectraNet's forecast capex.

Table 12 Impact on capex of AER draft decision on real cost escalation ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	2.9	5.9	10.6	12.5	11.0	42.9
AER draft decision	2.9	5.4	8.0	8.7	8.7	33.6
Difference	0.0	0.5	2.6	3.9	2.3	9.3

Source: AER analysis.

Strategic land and easements capex

The AER does not accept ElectraNet's proposed strategic land and easements capex of $65.8 million ($2012–13). ElectraNet's forecast of strategic land and easements capex was not supported by a robust cost–benefit analysis. Eleven of ElectraNet's 21 proposed land and easements projects are designated for ElectraNet's use by planning instruments such as the 30 Year Greater Adelaide Plan and council designations. An additional ten projects are not subject to planning

[74] NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).

instruments but are in regional and remote locations. Given this, there is a low risk that this land will be encroached upon. Further, 14 of ElectraNet's 21 strategic land and easements projects are not required to meet demand until the 2023–28 regulatory control period. For these reasons, the AER considers ElectraNet has been overly cautious in developing its forecast capex for strategic land and easements.

The AER considers that some level of strategic land and easements could be justified. The AER has therefore accepted EMCa's recommendation that $13.4 million ($2012–13) million of strategic land and easements capex be accepted.

Load driven capex

The AER has not accepted ElectraNet's demand forecast (see section 7). As a result, a reduction of $103.7 million ($2012–13) to ElectraNet's proposed load driven capex forecast is necessary to account for the lower demand forecast. This is comprised of:

- a $17.6 million ($2012–13) reduction to augmentation capex
- a $29.6 million ($2012–13) reduction to connection capex
- a $56.5 million ($2012–13) reduction to replacement capex as a result of the deferral of replacement programs.

The AER considers that $49 million ($2012–13) of proposed augmentation and connection capex projects are not load driven and therefore should not be subject to any reduction. The AER also considers that forecast capex in relation to projects already commenced — $28 million ($2012–13) of augmentation projects and $56 million ($2012–13) of connection projects — should not be adjusted. Based on the information before it, the AER has deferred the remaining augmentation and connection capex projects by 3 years.

ElectraNet advised the AER that a lower demand growth scenario would also impact its forecast replacement capex as it would allow several replacement projects to be deferred.[75] Based on this information, the AER has also adjusted replacement capex associated with load growth.

[75] ElectraNet, *Response to AER information request AER RP 16: CAPEX impact of AEMO's 2012 demand forecast ENET238*, August 2012, pp. 2–3.

10 Operating expenditure

Forecast opex is a forecast of the operating, maintenance and other non–capital costs incurred in the provision of prescribed transmission services. Opex includes labour costs and other non–capital costs.

ElectraNet's opex is divided into controllable and non–controllable opex. Controllable opex is in turn divided into direct operating and maintenance costs and other controllable costs. Direct operating and maintenance costs are comprised of:[76]

- field maintenance, which is comprised of three categories:
    - routine maintenance – field inspections and maintenance activities that are completed to a predetermined schedule and scope
    - corrective maintenance – field activities to mitigate short term risks and restore the condition or function of a transmission system asset, or component, to a satisfactory operational state
    - operational refurbishment – planned maintenance project activities to mitigate medium term risks identified through asset condition assessments and to provide asset information required to manage compliance with legal obligations and good electricity industry practice
- network optimisation – improving the capability to the network in order to release additional capacity and defer the need for capital investment
- maintenance support – costs related to managing field operating and maintenance contracts, environment and safety management, asset condition monitoring and analysis, works planning and coordination.
- network operations – costs associated with the control centre and other network operations activities.

Other controllable opex is comprised of:

- Asset manager support – functional activities that support the strategic development and ongoing management of the network. This includes network planning, customer and regulatory support and IT support.
- Corporate support – activities required to ensure effective corporate governance and business administration. This includes finance, accounting, administration, legal counsel, employee relations, health and safety and internal audit.

ElectraNet's non–controllable opex is comprised of:

- Self insurance – costs related to certain risk events where ElectraNet has decided to internally manage the risk. This is generally because external insurance is unavailable or uneconomical.
- Network support – payments for non-network solutions contracted by ElectraNet as cost effective alternatives to network augmentation. For example, local generation or demand management arrangements.

[76] ElectraNet, *Revenue proposal*, pp. 88–91.

- Debt raising costs – debt financing or transaction costs related to the raising of debt to fund capital investments.

The AER must accept ElectraNet's proposed forecast opex for the 2013–18 regulatory control period if it is satisfied the forecast reasonably reflects:

- the efficient costs to achieve the opex objectives, which are:[77]
  - meet the expected demand for prescribed transmission services over the regulatory control period
  - comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services
  - maintain the quality, reliability and security of supply of prescribed transmission services; and
  - maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.
- the costs that a prudent operator in the circumstances of ElectraNet would require to achieve the opex objectives;[78] and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[79]

If the AER is not satisfied that the forecast opex reflects the above criteria, then it must not accept the forecast opex and must determine a substitute forecast opex.[80]

The AER examined key documents, processes and assumptions, and compared historical expenditure to the forecast opex to fully understand the key drivers of ElectraNet's proposed forecast opex. The AER also engaged EMCa to provide expert advice on ElectraNet's proposed forecast opex.

Attachment 5 sets out the AER's detailed reasons for its draft decision on ElectraNet's forecast opex.

10.1 Draft decision

The AER does not accept ElectraNet's proposed total opex forecast of $478.1 million ($2012–13) for the 2013–18 regulatory control period.

The AER substituted its own forecast opex which was developed using a top down approach, but with 'step changes' included to reflect ElectraNet's changing business environment. The AER's substitute forecast opex for the 2013–18 regulatory control period is $397.6 million ($2012–13), which is $80.5 million ($2012–13) or 17 per cent less than ElectraNet's proposed forecast opex. But this opex allowance is still a 17 per cent real increase on the 2008–13 total opex allowance. Table 13 shows the AER's draft decision on ElectraNet's forecast opex.

77 NER, clause 6A.6.6(a).
78 NER, clause 6A.6.6(c)(2).
79 NER, clause 6A.6.6(c)(3).
80 NER, clause 6A.6.6(d).

Table 13 AER draft decision on ElectraNet's proposed forecast opex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	88.8	95.8	96.2	98.3	99.0	478.1
AER draft decision	75.0	78.3	79.3	82.0	83.1	397.6
Difference	–13.8	–17.5	–16.9	–16.3	–15.9	–80.5

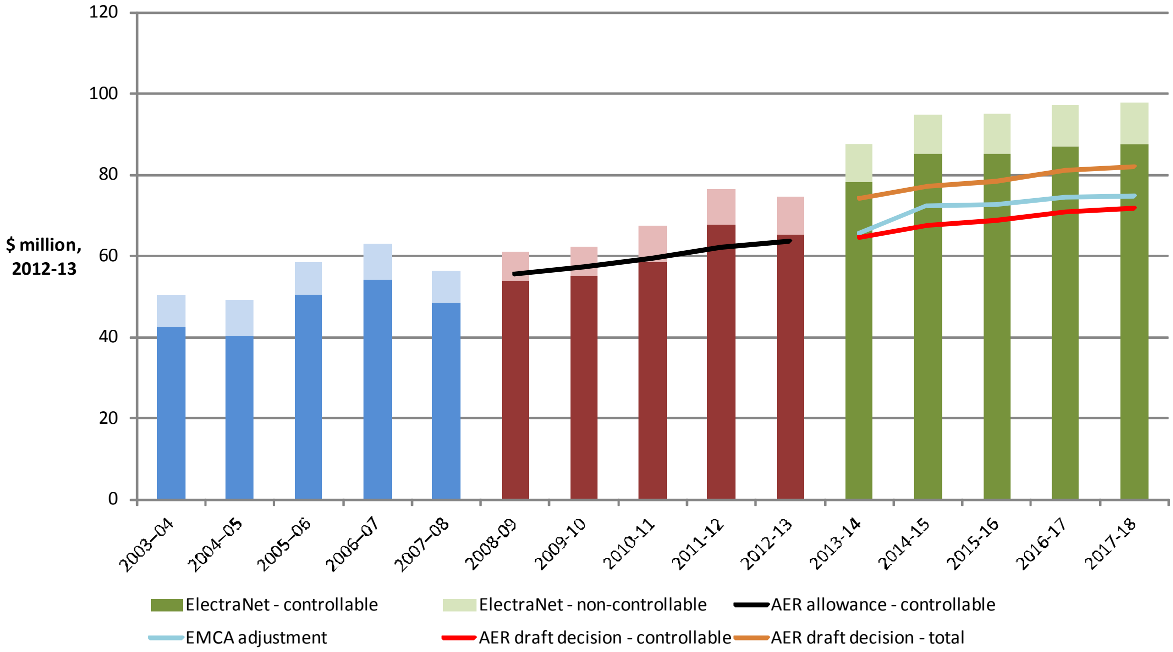
Source: ElectraNet, *Revenue proposal*, p. 112 and AER analysis.

10.2 Summary of analysis and reasons

10.2.1 Historical opex

Figure 14 shows the AER's draft decision on ElectraNet's forecast opex and compares it with ElectraNet's proposed forecast opex and ElectraNet's historical opex.

Figure 14 AER draft decision on ElectraNet's proposed forecast opex ($ million, 2012–13)



Source: AER analysis based on ElectraNet revenue proposal and ENET100.

10.2.2 ElectraNet's forecast opex

The AER examined ElectraNet's proposed forecast opex using two approaches: a 'top down' approach' and a detailed 'bottom up' technical review. Both reviews showed that ElectraNet's forecast opex for the 2013–18 regulatory control period is higher than necessary.

The AER used the top down approach to estimate a substitute forecast opex. The top down approach used a base-year-extrapolated method. This involves determining an 'efficient base year' that reflects ElectraNet's efficient opex. The forecast opex is then extrapolated from this base year. The extrapolated costs can be adjusted for any 'step changes' as necessary. Step changes allow additional funding where the service provider faces a new requirement or change in circumstance requiring it to undertake additional expenditure that was not accounted for in the base year. Examples of step changes are new safety regulations or new maintenance projects.

Base year costs

The AER used 2010–11 as the base year for its top down opex approach. The 2010–11 costs are audited actual costs, and are closer to the historical opex trend than ElectraNet's proposed 2011–12 base year. On this basis, the AER considers that 2010–11 costs better reflect ElectraNet's efficient costs.

Step changes

ElectraNet proposed step changes in its field maintenance requirements (driven by its significant investment in its new asset management framework), new accommodation, superannuation and network optimisation opex categories. The largest proposed step change was for field maintenance. ElectraNet proposed field maintenance expenditure that is a 57 per cent real increase on the 2008–13 field maintenance expenditure and which exceeds the historical trend by about $52.9 million. The other proposed step changes total $15.4 million.

The AER accepted some of ElectraNet's proposed step changes. However, the AER does not accept the majority of the step changes proposed. The AER's assessment of ElectraNet's proposed step changes is in appendix A.

Escalation for network growth

Asset growth

ElectraNet applied asset growth factors to escalate its base year opex to account for its expanding network. Its proposed asset growth factors were based on the depreciated RAB values in the base year. The AER does not accept ElectraNet's method for estimating asset growth because that method overestimated the forecast opex. The depreciated RAB value underestimates the physical size of ElectraNet's network in the base year, and thus the asset growth factors calculated using that value overestimated the network growth rates. This overestimation occurs because the depreciated RAB value is used as the denominator when calculating the asset growth factors. Instead, the AER applied an estimated undepreciated RAB.[81] The AER requested ElectraNet provide an estimated undepreciated RAB value for the purposes of the asset growth calculation. However, ElectraNet responded that it does not have an undepreciated RAB value.[82] The AER therefore has estimated an undepreciated RAB value for 2010–11 by adding the accumulated straight-line depreciation from 2002 to 2010 to the depreciated RAB value at 30 June 2011. The AER also updated the asset growth factors to reflect the AER's draft decision on load driven capex, because load driven capex is used as an input for calculating the asset growth factors.[83] Further, the AER removed the impact of real cost escalation from the asset growth factors to avoid double counting because real cost escalation has been separately accounted for in the opex model.

Economies of scale

ElectraNet's proposed asset growth factors incorporate economies of scale factors. This is because asset growth does not result in a one for one increase in opex for all operating cost categories.

81 The AER has requested ElectraNet to provide an estimated undepreciated RAB value to the AER for the purposes of asset growth factors. However, ElectraNet responded that it does not have an undepreciated RAB value. The AER therefore has estimated an undepreciated RAB value for 2010-11 by adding the accumulated straight-line depreciation over 2002 to 2011 to the depreciated RAB value at 30 June 2011.

82 ElectraNet, Email response to information request AER RP36 openx model assumption, ENET278, p. 4.

83 Based on as-commissioned load driven capex. ElectraNet, Email response to information request AER RP36 opex model, ENET273, pp. 2. ElectraNet, Email response to information request AER RP36 opex model, ENET278, p. 4.

However, ElectraNet changed its economies of scale factors from 0.25 to 0.40 for network operations and from 0.10 to 0.25 for its asset manager support. The materiality of these changes is about $1.7 million. The AER is not satisfied ElectraNet's reason for the increase in scale factors is sufficient to demonstrate the proposed opex forecast is a realistic expectation of cost inputs. The AER adopted the same economies of scale factors approved for the 2008–13 regulatory control period for these categories.

ElectraNet proposed an economies of scale factor of 100 per cent for its direct charges. Direct charges falls within the maintenance support category which has an economies of scale factor of 25 per cent. ElectraNet stated that direct charges such as land tax have no efficiencies available as they are externally driven and directly proportional to asset growth. The AER note that land tax forms a large proportion of the costs in this sub-category. Since land tax is forecast using a zero-based method, it does not require an economies of scale factor. For the remaining direct charges, the AER applied an economies of scale factor of 25 per cent, which is consistent with the economies of scale factor of the maintenance support category.

Labour and materials escalators

As discussed in section 9.2.2 the AER has amended ElectraNet's real cost escalators which impacted the AER's draft decision on ElectraNet's forecast opex.

Opex efficiency factor

ElectraNet recognised the scope for continuous improvement and has a formalised improvement and innovation program in place from which it has identified inefficiencies in its current practices. ElectraNet has implemented solutions to reduce such inefficiencies. ElectraNet identified efficiency savings for routine maintenance of about 5 per cent. The AER considers that ElectraNet can achieve efficiencies in other opex categories as well.

EMCa advised that it was reasonable to apply a 2.5 per cent efficiency factor across the entire forecast opex. The AER agrees with EMCa, and has applied an efficiency factor of 2.5 per cent to the rest of ElectraNet's forecast opex.

Bottom up technical review

The AER's bottom up technical review, supported by advice from EMCa, supported the AER's conclusion that ElectraNet's forecast opex did not meet the opex criteria. EMCa recommended that ElectraNet's controllable opex should be reduced by $63.2 million ($2012–13).

10.3 Efficiency benefit sharing scheme

The EBSS provides a continuous incentive to reduce opex. When an efficiency benefit is realised (the TNSP spends less than forecast) the cost saving is retained by the TNSP for five years before being passed on to consumers. However, when an efficiency loss is realised (the TNSP spends more than forecast) the TNSP is penalised by the same mechanism.

The choice of base year influences the EBSS rewards and penalties adjustments to the TNSP's annual revenue requirement, but it also affects the magnitude of the opex forecast (and therefore the revenue requirement). These adjustments form the EBSS building block of a TNSP's revenue.

The AER must adjust a TNSP's 2013–18 regulatory control period revenues for efficiency gains or losses made in the 2008–13 regulatory control period. The AER does not accept ElectraNet's proposed penalty of $12.2 million ($2012–13) because it does not comply with the requirements of the EBSS.

The AER used 2010–11 as the base year for its substitute forecast opex rather than the 2011–12 base year proposed by ElectraNet. This is because 2010-11 costs were revealed to be more representative of efficient and recurrent costs.

The AER modelled the impact of the change in the base year, from 2011–12 (as proposed by ElectraNet) to 2010–11. The EBSS penalty is $4.5 million when 2010–11 is used as the base year. The EBSS penalty is $26.9 million when 2011–12 is used. However, the difference between the penalties is almost entirely compensated for by the lower opex forecast driven by the different base year. That is, the EBSS carryover amount cannot be considered independently of total forecast opex. The AER found that the total outcome from changing the base year from 2011–12 to 2010–11 resulted in a relatively small difference between the two scenarios in the 2013–18 regulatory control period. The AER selected 2010–11 as the base year, because it better represented recurrent costs.

The 'first proposed EBSS' applied to ElectraNet in the 2008–13 regulatory control period.[84] The 'final EBSS' will apply to ElectraNet for the 2013–18 regulatory control period.[85]

[84] AER, *Electricity transmission network service providers efficiency benefit sharing scheme*, January 2007.
[85] AER, *Electricity transmission network service providers efficiency benefit sharing scheme*, September 2007.

11 Corporate income tax

The estimated cost of corporate income tax is one of the building blocks used to determine the total revenue requirements for ElectraNet over the 2013–18 regulatory control period. Total revenue requirements are calculated on a post–tax basis using the AER's PTRM. As such, an allowance must be calculated to enable ElectraNet to recover the costs associated with the estimated corporate income tax payable during the 2013–18 regulatory control period.

The AER uses the PTRM to produce an estimate of the taxable income that would be earned by an efficient company operating the South Australian transmission network. The AER modelled ElectraNet's tax expenses over the 2013–18 regulatory control period using a gearing ratio of 60 per cent. Tax depreciation is calculated using a separate tax asset base (TAB). All tax expenses are offset against ElectraNet's forecast revenue to estimate the taxable income. The statutory income tax rate of 30 per cent is then applied to the estimated taxable income to arrive at a notional amount of tax payable. The AER then applies a discount to this to account for the assumed utilisation of imputation credits (gamma), which has a value of 0.65. This amount is then included as a separate building block to determine ElectraNet's total revenue.

Attachment 9 sets out the AER's detailed reasons for its draft decision on corporate income tax.

11.1 Draft decision

The AER does not accept ElectraNet's proposed corporate income tax allowance of $30.7 million ($ nominal) for the 2013–18 regulatory control period. The AER's draft decision on ElectraNet's corporate income tax allowance is $26.8 million, which represents a reduction of $3.9 million (or 12.7 per cent) to the proposal.

Based on the approach to modelling cash flows in the PTRM, the AER has derived an effective tax rate of 24.0 per cent for this draft decision. Table 14 shows the AER's draft decision on ElectraNet's corporate income tax allowance.

Table 14 AER draft decision on ElectraNet's corporate income tax allowance ($million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Tax payable	13.8	14.6	15.6	17.8	14.9	76.7
Less: value of imputation credits	9.0	9.5	10.1	11.6	9.7	49.9
Net corporate income tax allowance	4.8	5.1	5.4	6.2	5.2	26.8

11.2 Summary of analysis and reasons

The AER has reduced ElectraNet's proposed corporate income tax allowance of $30.7 million by $3.9 million (or 12.7 per cent) to $26.8 million ($ nominal). This reduction has been made for the following reasons:

- The AER accepts ElectraNet's proposed method to establish the opening TAB as at 1 July 2013. However, the AER increased ElectraNet's proposed TAB as at 1 July 2013 to $1407.0 million

($ nominal) from $1405.0 million. This is because the AER adjusted the actual capex values and removed two incorrect adjustments to the opening TAB values in the RFM.

- The AER accepts ElectraNet's proposed standard tax asset lives for the majority of its asset classes, except for the 'Equity raising cost 2013–18' and 'Transmission line refit' asset classes. The AER changed the proposed standard tax asset life for the 'Equity raising cost 2013–18' asset class to 5 years from 43 years. It changed the proposed standard tax asset life for the 'Transmission line refit' asset class to 27 years from 47.5 years.

- The AER accepts ElectraNet's proposed weighted average method to calculate the remaining tax asset lives at 1 July 2013. In accepting the weighted average method, the AER has updated the proposed remaining tax lives to reflect the AER's adjustments to ElectraNet's actual capex in the RFM.

The AER's determinations on other building blocks including forecast opex (attachment 5) and cost of capital (attachment 6) also impact the estimated corporate income tax allowance.[86]

86 NER, clause 6A.6.4.

12 Contingent projects

Contingent projects are significant network augmentation projects that may arise during the regulatory control period but are not yet committed and are not provided for in the capex forecast. Contingent projects are linked to unique investment drivers (such as expectations of load growth in a particular region) and are triggered by a defined 'trigger event'.[87] Under the NER, the occurrence of the trigger event must be probable.[88] However, the event or the costs associated with the event must be uncertain.[89]

If a trigger event occurs during the 2013–18 regulatory control period, the AER will assess the contingent project's costs on application by ElectraNet. If the AER approves the contingent project's costs at that time, the AER will amend ElectraNet's determination to account for the increased costs associated with the contingent project.

ElectraNet proposed 21 contingent projects with a combined value of $2547 million ($2012–13). This is a 150 per cent increase on the contingent capex allowed by the AER for the 2008–13 regulatory control period. Attachment 13 sets out the detailed reasons for the AER's draft decision on ElectraNet's contingent projects.

12.1 Draft decision

The AER does not accept any of ElectraNet's proposed contingent projects because they do not meet the NER requirements. The AER considers that five of ElectraNet's proposed contingent projects could meet the NER requirements but the trigger events are not appropriate. The AER grouped the proposed contingent projects as follows:

- Projects associated with general load growth
- Projects that are not considered probable during the 2013–18 regulatory control period
- Projects that could meet the NER but the trigger events are not appropriately defined.

12.2 Projects associated with general load growth

The AER determined that several of ElectraNet's proposed contingent projects sat in a band between its medium and high demand scenarios. The AER considered that ElectraNet's forecast capex would be sufficient to meet these contingent projects that were triggered by demand increases between ElectraNet's medium and high demand scenarios. If these projects were to be included as contingent projects then customers may be required to compensate ElectraNet twice for the same risks. For these reasons, the AER does not accept the following categories of contingent projects:

- Projects associated with general load growth — ElectraNet proposed two contingent projects which are triggered by a demand increase that ElectraNet forecast will occur in the 2013–18 regulatory control period. The AER does not accept these two projects.
- Projects triggered by a connection point request but within demand forecast — ElectraNet proposed four contingent projects for new connection points which appear to be driven by demand increases that are within ElectraNet's demand forecast for the 2013–18 regulatory control period. The AER does not accept these four projects.

87 NER, clause 6A.8.1(c)(5).
88 NER, clause 6A.8.1(c)(5).
89 NER, clause 6A.8.1(c)(5)(i).

In light of the AER's revised demand forecast, the AER considers that some of these contingent projects might now be relevant if a lower demand forecast is applied in the final decision. It might therefore be necessary for ElectraNet to propose some additional contingent projects in its revised revenue proposal. However, ElectraNet would need to justify adding any contingent projects, including identifying the underlying driver of the projects.

12.2.1 Projects that are not probable during the regulatory control period

Projects that require a step change in demand or new generation—before they are triggered—may be included as contingent projects. The AER would, however, expect ElectraNet to justify the inclusion of the contingent project by identifying the driver of the project that will make the occurrence of the trigger event probable during the 2013–18 regulatory control period. The AER therefore does not accept the following categories of contingent projects.

- Projects for which the demand increase is not justified — ElectraNet included four proposed contingent projects for which it nominated a demand increase above its high demand forecast scenario for the 2013–18 regulatory control period as the trigger event. ElectraNet did not identify the reason for why this demand increase may occur. As such, the AER is not satisfied that the projects are reasonably required, and that the occurrence of the trigger events are probable and or that the trigger event is specific. For these reasons the AER does not accept these four contingent projects.

- Projects driven by the expansion of Olympic Dam — ElectraNet included two proposed contingent projects are associated with the expansion of BHP Billiton's Olympic Dam mine. As BHP Billiton announced that it would defer expansion of the mine, the AER considers that these projects are not reasonably required during the 2013–18 regulatory control period. Alternatively, they will not be required as scoped. As such, the AER does not accept these two contingent projects.

- Market benefits projects — ElectraNet proposed three market benefits projects for which the trigger event was a general reference to new generation or load coming on line. ElectraNet did not identify that generation is likely to occur, only that it was a possibility. The AER therefore does not accept these three contingent projects.

- Projects which do not appear to be feasible — the AER considers that one of the proposed contingent projects, Eyre Peninsula Connection Point, is not technically feasible as presented and therefore does not accept this contingent project.

12.2.2 Projects the AER considers might satisfy the NER requirements

The AER considers that five of ElectraNet's proposed contingent projects might meet the NER requirements. However, the AER has not accepted these projects because the trigger events proposed for these contingent projects were not well defined and do not meet the NER requirements. The AER therefore proposed alternative trigger events for these projects set out at appendix C.

- Davenport Reactive Support – $42 million ($2012–13)
- Mid North Connection Point – $59 million ($2012–13)
- Upper North Region Line Reinforcement – $62 million ($2012–13)
- Riverland Reinforcement – $407 million ($2012–13)
- South East to Heywood Interconnection Upgrade – $96 million ($2012–13).

13 Service target performance incentive scheme

The service target performance incentive scheme has two components. The first component is the 'service component'. This provides a financial incentive for transmission network service providers (TNSPs) to improve and maintain their service performance. This incentive counters the financial incentive under revenue regulation to reduce costs at the expense of service performance. A TNSP's performance is compared against the performance target for each parameter during the regulatory control period. The TNSP may receive a financial bonus for service improvements, or a financial penalty for declines in service performance. The financial bonus (or penalty) is limited to 1 per cent of the TNSP's maximum allowed revenue (MAR) for the relevant calendar year.

The second component is the 'market impact component'. This provides financial rewards to TNSPs for improvements in its performance measure against a performance target. ElectraNet may earn an additional revenue increment of up to 2 per cent of its MAR for the relevant calendar year. Unlike the service component, there is no financial penalty associated with the market impact component.

Attachment 11 sets out the AER's detailed reasons for its draft decision on the STPIS.

13.1 Draft decision

Service component

The AER does not accept ElectraNet's proposed service component parameter values and weightings. Table 15 shows the AER's draft decision on ElectraNet's proposed service component parameter values and weightings.

Table 15 AER draft decision on ElectraNet's parameter values and weightings for the service component of the STPIS

	Collar	Target	Cap	Weighting (% of MAR)
Transmission circuit availability (%)				
Transmission circuit availability	99.02	99.52	99.68	0.3
Critical circuit availability peak	97.36	99.12	99.96	0.1
Critical circuit availability non peak	98.25	99.37	99.87	0.0
Loss of supply event frequency (no. of events)				
> 0.05 system minutes	9	7	4	0.2
> 0.2 system minutes	4	2	0	0.2
Average outage duration (minutes)				
Average outage duration	323.2	203.2	83.2	0.2
Total weighting (% MAR)				1.0

Source: AER analysis.
Note: Subsequent to submitting its revenue proposal, ElectraNet resubmitted its STPIS data. The AER provided ElectraNet with the principles to derive the AER draft decision STPIS parameter values. ElectraNet applied these principles to its resubmitted STPIS data and provided the draft decision STPIS parameter values.

Market impact component

The AER does not accept ElectraNet's proposed market impact component STPIS parameter values as the AER identified several errors in ElectraNet's calculation of it. Table 16 shows the AER's draft decision on ElectraNet's proposed market impact component target and cap.

Table 16 AER draft decision on ElectraNet's parameter values and weightings for the market impact component of the STPIS

	Target	Cap	Weighting (% of MAR)
Market impact parameter (dispatch intervals)	1585	0	2.0

Source: AER analysis.

13.2 Summary of analysis and reasons

Service component

The AER does not accept ElectraNet's proposed service standard parameter values and weightings because:

- erroneous historical performance data was used to calculate the targets, caps and collars in ElectraNet's revenue proposal
- the proposed service component parameter weightings do not satisfy clause 3.5 of the STPIS and have not been sufficiently justified
- the methodology used to adjust performance targets for forecast capex volumes is inappropriate
- the exclusion of outages associated with contingent projects is not allowed under the STPIS.

The AER considered that ElectraNet's method of calculating the STPIS caps and collars was not sound. However, the caps and collars calculated in accordance with the AER's preferred method did not result in materially different caps and collars that influenced the effectiveness of the STPIS. As such, the AER accepted ElectraNet's proposed caps and collars.

Erroneous data used to calculate performance targets, caps and collars

The STPIS values in ElectraNet's revenue proposal were calculated from data that had not been reviewed by the AER. ElectraNet subsequently resubmitted its STPIS values calculated from data that was annually reviewed by the AER. The AER's draft decision assessed this resubmitted data.

Revenue weightings for service component parameters

The AER accepts ElectraNet's proposed changes to the weightings for the 'critical circuit availability – peak' sub–parameter. However, the AER does not accept ElectraNet's proposed weightings for the 'loss of supply event > 0.05 system minutes' sub–parameter and the 'average outage duration' parameter. ElectraNet did not justify why a higher weighting was necessary for the 'average outage duration' parameter. The AER considers that an increase in the weighting for the 'loss of supply events 0.05 system minutes' sub–parameter is necessary to accommodate the decreased weighting for the 'critical circuit availability – peak' sub–parameter.

Adjustments to reliability targets for proposed capital works

The AER does not accept ElectraNet's proposed adjustments to the targets for the three reliability sub–parameters. ElectraNet's method of calculating the adjustment used assumptions that are likely to result in an inaccurate figure. The AER considers that an adjustment should be made using a bottom up estimate of the effect of capital works on reliability.

Exclusion of outages associated with contingent projects

The AER does not accept ElectraNet's proposal to exclude the effects on reliability from contingent projects. The STPIS does not allow new exclusions to be determined in a TNSP's transmission determination.

Market impact component

The AER does not accept ElectraNet's proposed market impact component STPIS parameter values. The AER's draft decision has corrected several errors that were identified in ElectraNet's calculation of the market impact component values.

14 Pricing methodology

A pricing methodology is a method, formula, process or approach that allocates the aggregate annual revenue requirement (AARR) to the categories of prescribed transmission services that the TNSP provides and to the network connection points of network users.[90] It also determines the structure of prices that a TNSP may charge for each category of prescribed transmission services.[91]

Two TNSPs provide prescribed transmission services in South Australia: ElectraNet and Murraylink. Under the NER if more than one TSNP provides prescribed transmission services in a region, then those providers must appoint a coordinating network service provider that is responsible for allocating all relevant AARR in that region.[92] In South Australia, ElectraNet was appointed the coordinating network service provider, and so is responsible for allocating both ElectraNet's and Murraylink's AARR.

Attachment 14 sets out the AER's detailed reasons for its draft decision on ElectraNet's pricing methodology.

14.1 Draft decision

The AER approves the pricing methodology proposed by ElectraNet for the 2013-18 regulatory control period. It is satisfied the proposed pricing methodology:

- gives effect to, and complies with, the pricing principles for prescribed transmission services; and
- complies with the information requirements of the pricing methodology guidelines.[93]

14.2 Summary of analysis and reasons

ElectraNet's proposed pricing methodology is largely the same as its existing methodology.[94] The AER's assessment therefore focused on the changes ElectraNet proposed to introduce in the 2013–18 regulatory control period. These are:

- the modification of ElectraNet's priority ordering methodology; and
- the introduction of standby service arrangements with network customers.

ElectraNet proposed to modify its priority ordering methodology to incorporate the amendments to clause 11.6.11 of the NER. The changes introduced by that amendment relate to the cost allocation of assets grandfathered as prescribed transmission services (primarily assets providing services to SA Water).[95]

Standby service arrangements allow network customers to contract to an agreed maximum demand under normal operating conditions and a greater demand on a standby basis. It allows some network customers to increase their load above the agreed maximum demand in their connection agreement

90 NER, clause 6A.24.1(b)(1).
91 NER, clause 6A.24.1(b)(2).
92 NER, clause 6A.29.1(a).
93 NER, clause 6A.24.1(c)
94 ElectraNet, *Revised Proposed Pricing Methodology 1 July 2008 to 30 June 2013*, December 2007. The changes to clause 11.6.11 took effect in 2009, whereas ElectraNet submitted its existing pricing methodology to the AER for approval in December 2007.
95 Australian Energy Market Commission, Rule Determination: National Electricity Amendment (Cost allocation arrangements for transmission services) Rule 2009 (Rule Proponent: National Generators Forum)

without incurring a penalty. The availability of this arrangement is subject to the discretion of ElectraNet and the operational conditions of the transmission network.

The AER is satisfied that these changes are consistent with the requirements of the NER.

15 Negotiated transmission services

The AER's transmission determination imposes control over revenues that a TNSP can recover from the provision of prescribed transmission services. Negotiated transmission services do not have their terms and conditions determined by the AER. Under the NER, these services are subject to negotiation between parties, or alternatively arbitration and dispute resolution by a commercial arbitrator. These processes are facilitated by:[96]

- a negotiating framework; and
- negotiated transmission service criteria (NTSC)

A TNSP must prepare a negotiating framework which sets out procedures for negotiating the terms and conditions of access to a negotiated transmission service.[97] The NTSC set out criteria that a TNSP must apply in negotiating terms and conditions of access, including the prices and access charges for negotiated transmission services.[98] They also contain the criteria that a commercial arbitrator must apply to resolve disputes about such terms and conditions and/or access charges.[99]

Attachment 15 sets out the AER's detailed reasons for its draft decision on ElectraNet's negotiated services.

15.1 Draft decision

The AER does not approve ElectraNet's proposed negotiating framework because the proposal does not comply with the NER requirements in clause 6A.9.5(c). The following paragraphs of the proposed negotiating framework should be amended:

- paragraph 6.3.1, which seeks to give effect to sub-clauses 6A.9.5(c)(3)(i) and(ii) of the NER
- paragraph 7.2, which contains a citation error in referencing another part of ElectraNet's proposed negotiating framework
- paragraph 9.1.1, which seeks to give effect to clause 6A.9.5(c)(5) of the NER.

The AER's draft decision is that the AER's proposed NTSC for ElectraNet published in June 2012 will apply to ElectraNet in the 2013–18 regulatory control period. The proposed NTSC gives effect to the negotiated transmission service principles provided in clause 6A.9.1 of the NER.

15.2 Summary of analysis and reasons

The AER does not approve ElectraNet's proposed negotiating framework because it does not accurately specify the requirements of clause 6A.9.5(c) the NER. In particular, clause 6A.9.5(c)(5) and sub-clauses 6A.9.5(c)(3)(i) and (ii) of the NER are not accurately reflected in ElectraNet's proposed negotiating framework. The proposed negotiating framework also contains a citation error in paragraph 7.2.

96 NER, clause 6A.9.2.
97 NER, clause 6A.9.5(a).
98 NER, clause 6A.9.4(a)(1).
99 NER, clause 6A.9.4(a)(2).

16 Cost pass through

The pass through mechanism of the NER allows TNSPs to recover the costs of defined unpredictable, high-cost events which are not built into the transmission determination. The pass through events specified in the NER for TNSPs are:

- a regulatory change event
- a service standard event
- a tax change event
- an insurance event.[100]

In August 2012, the Australian Energy Market Commission (AEMC) made a rule determination on the NER's cost pass through provisions which gave TNSPs the ability to nominate additional pass through events as part of their revenue proposals.[101] ElectraNet proposed the AER approve three additional pass through events:[102]

- a terrorism event
- a natural disaster event
- an insurance cap event.

16.1 Draft decision

The AER accepts a terrorism event, as proposed by ElectraNet, as a nominated pass through event.

The AER does not accept a natural disaster event and an insurance cap as nominated pass through events in the forms proposed by ElectraNet. Before it can accept these events as nominated pass through events, the AER requires ElectraNet to amend its definitions.

16.2 Summary of analysis and reasons

The AER requires ElectraNet to amend its definition of a natural disaster event and an insurance cap event, as set out in attachment 16. The revised definitions preserve the incentives for ElectraNet to efficiently manage the risks of such events through commercial and self insurance.

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100 An insurance event is different to an insurance cap event.

101 AEMC, *Rule determination, National electricity amendment (cost pass through arrangements for network service providers) rule 2012*, 2 August 2012, p. 31.

102 ElectraNet, *Pass through event proposal*, 29 August 2012.

Attachments

1 Real cost escalation

Real cost escalation is a method for accounting for expected changes in the costs of key input factors. Due to market forces these costs may not increase at the same rate as inflation.

1.1 Draft decision

Overall, the AER does not accept that ElectraNet's proposed real cost escalators reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[103] However, there are parts the AER does accept. It has determined the substitute escalators in Table 1.1, which reflect the AER's considerations that:

- labour cost forecasts developed by Deloitte Access Economics (DAE) reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives
- exchange rates and forecast inputs for material and land value escalation should be updated to reflect most recent data
- applying land type escalators to corresponding land and easement projects reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.

103 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).

Table 1.1 AER draft decision on real cost escalators (per cent)

	2013-14	2014-15	2015-16	2016-17	2017-18
Internal labour	2.0	2.0	0.7	0.7	1.0
External labour	1.7	1.1	0.6	0.2	0.5
Residential land	8.1	8.1	8.1	8.1	8.1
Commercial land	5.4	5.4	5.4	5.4	5.4
Rural land	4.9	4.9	4.9	4.9	4.9
Other land	5.9	5.9	5.9	5.9	5.9
Total land	6.9	6.9	6.9	6.9	6.9
Aluminium	6.5	4.8	6.5	6.9	1.1
Copper	1.4	0.0	–3.8	–8.7	–3.2
Steel	5.0	–1.1	–1.1	3.8	3.9
Crude oil	0.1	–3.1	–2.4	–1.6	–1.8
Construction	0.5	0.2	–0.1	0.0	0.0
Weighted average material	2.2	1.2	0.3	0.6	0.9

Source: AER analysis, Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia,* 15 October 2012.

1.2 ElectraNet's proposal

ElectraNet included an allowance for forecast real labour cost increases—that is, cost increases greater than the forecast inflation rate—in both its opex and capex forecasts.[104] It also included an allowance for forecast movements in materials and land values in its forecast capex. For material escalation, ElectraNet has applied an overall weighted average of inputs which includes the labour and land value escalators. Table 1.2 provides ElectraNet's real cost escalation forecasts.

104 ElectraNet, *Revenue proposal*, pp. 68–72, 102–103.

Table 1.2 ElectraNet's real cost escalation forecasts (per cent)

	2013-14	2014-15	2015-16	2016-17	2017-18
Internal labour	2.0	2.0	2.3	2.5	2.8
External labour	3.1	2.6	1.9	2.5	3.0
Land	7.0	7.0	7.0	7.0	7.0
Aluminium	5.3	3.9	2.9	2.5	2.0
Copper	0.4	–1.5	–3.4	–3.9	–4.5
Steel	3.5	1.8	0.3	–0.1	–0.6
Crude oil	–2.2	–3.4	–2.4	–1.5	–1.2
Construction	–0.6	–0.3	0.1	0.6	0.9
Weighted average	2.1	1.7	1.5	1.7	1.9

Source: ElectraNet, BIS Shrapnel, *Labour cost escalation forecasts to 2017/18-Australia and South Australia.*

For labour cost escalation, ElectraNet proposed:[105]

- its current enterprise agreement (EA) outcomes, where applicable
- forecast labour price index (LPI) unadjusted for productivity in all other instances.

ElectraNet engaged BIS Shrapnel for advice on the labour cost outlook.[106] The BIS Shrapnel LPI forecast recommended:

- forecast growth for the electricity, gas and water (EGW) industry for internal labour,[107]
- forecast growth for the construction industry for external labour.[108]

ElectraNet also proposed real cost escalation be applied to its materials inputs.[109] It engaged Competition Economists Group (CEG) to provide advice. CEG's advice also provided commentary on future movements in labour costs. CEG considered:

- actual measures of labour costs (such as enterprise agreements) should be preferred to broader measures
- the use of LPI is only valid in the situation where promoting/hiring more skilled workers occurs because a business is able to displace workers who are less skilled
- labour forecasts should not be adjusted for productivity gains.

105 ElectraNet, *Revenue proposal*, pp. 68–70, 102–103.
106 BIS Shrapnel, *Labour cost escalation forecasts to 2017/18-Australia and South Australia*, April 2012.
107 BIS Shrapnel, *Labour cost escalation forecasts to 2017/18-Australia and South Australia*, April 2012, p. 23.
108 BIS Shrapnel, *Labour cost escalation forecasts to 2017/18-Australia and South Australia*, April 2012, p. 53.
109 ElectraNet, *Revenue proposal*, pp. 71–72.

For material escalation, CEG was requested to forecast future input costs of aluminium, copper, steel, crude oil and construction based on future market prices and expert forecasts.[110] Material inputs were calculated in United States dollars ($US) and converted into Australian dollars ($AUD).

ElectraNet proposed a singular land value escalator based on historical South Australian land values over from June 1989 to June 2010.[111] It engaged Maloney Field Services to produce this forecast.[112]

1.3 Assessment approach

The AER assessed ElectraNet's proposed real cost escalators against the requirements in the NER. The AER must accept ElectraNet's opex and capex forecasts if satisfied the total forecasts reasonably reflect the opex and capex criteria.[113] To do this the AER must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the opex and capex objectives.[114]

In making its draft decision for labour cost escalation, the AER:

- reviewed the BIS Shrapnel report commissioned by ElectraNet[115]
- considered advice from its commissioned consultant, DAE[116]
- tested the experts forecasts against each other
- tested the EA against the expert's forecasts
- tested the EA against the market.

In making its draft decision for material cost escalation the AER reviewed ElectraNet's proposed input cost model, its inputs and its materiality on the total forecast capex. Where required the AER updated the inputs to reflect the most recent available information. The AER developed its own forecasts of materials price changes for material escalation. Where possible it forecast price changes from prices traded in futures markets, such as contracts traded on the London Metal Exchange (LME). Where these were unavailable it took forecasts from Consensus Economics, which provides forecasts derived from an average of forecasts from a number of economic forecasters.[117]

In making its draft decision for land value escalation the AER reviewed ElectraNet's proposed input cost model, its inputs and its materiality on the total forecast capex. Where required the AER updated the inputs to reflect the most recent available information.

In forming its views the AER has also taken into consideration submissions by stakeholders.[118]

1.4 Reasons for draft decision

The AER acknowledges there is no perfect predictor of escalators. This opinion is shared by expert forecasters.[119] Some forecasts are, however, more reliable than others, although the experts remain

110 ElectraNet, *Revenue proposal*, pp. 71–72.
111 ElectraNet, *Revenue proposal*, p. 71.
112 Maloney Field Services, *Valuation: ElectraNet site values for land tax*, May 2012.
113 NER, clauses 6A.6.6(c) and 6A.6.7(c).
114 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
115 BIS Shrapnel, *Labour cost escalation forecasts to 2017/18-Australia and South Australia*, April 2012.
116 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 15 October 2012.
117 Consensus Economics, *Energy and metals consensus forecasts*, 20 August 2012.
118 ECCSA, *ElectraNet SA Application: A response by the Energy Consumers Coalition of SA*, August 2012, p. 16.
119 Delloitte Access Economics, *Responses to BIS Shrapnel reports*, 30 July 2012; BIS Shrapnel, *Labour cost escalation forecasts to 2017/18-Australia and South Australia*, April 2012, pp. I–iii; CEG, *Escalation factors affecting expenditure forecasts: A report for ElectraNet*, May 2012, p. 13, paragraph 35.

divided. Consequently, the AER has considered a range of material and views in reaching a conclusion. The AER is not satisfied that in all instances the forecasts proposed by ElectraNet satisfy the requirements of the rules. In these instances the AER has substituted an alternative forecast.

1.4.1 Labour cost escalators

Overall, the AER does not accept that ElectraNet's proposed labour cost escalators reasonably reflect a realistic expectation of future labour costs. However, the AER considers part of the proposal is reflective of future labour costs given ElectraNet's circumstances. This is because the AER considers:

- forecast movements in labour costs for the electricity, gas, water and waste services (EGWWS) industry (rather than EGW industry) provides the most reliable forecast of movements in internal labour costs possible in the circumstances
- there is evidence to support ElectraNet's contention that its EA is a realistic expectation of cost inputs required to achieve the opex and capex objectives
- there has been a material change in circumstances since ElectraNet's proposed external labour cost escalators were produced and its proposal needs to be amended to reflect this change.

The following sections discuss these issues in detail.

Review of expert forecasts

The AER reviewed the forecasts provided by BIS Shrapnel and DAE. It noted that although both expert reports used LPI unadjusted for productivity to forecast internal labour costs they used different measures of labour force industries. The AER seeks to determine whether the use of ElectraNet's measure of labour force industries will provide a realistic expectation of cost inputs given ElectraNet's circumstances. If not, the AER can determine a more accurate predictor of escalators for the 2013–18 regulatory control period.

Use of labour force industries

The AER does not accept the use of the EGW industry data to estimate labour cost escalations for ElectraNet's internal labour. The AER is not satisfied that the use of the EGW industry reasonably reflects a realistic expectation of cost inputs required to achieve the opex and capex objectives.[120]

The AER considers where applicable using forecast growth in the EGWWS industry to escalate ElectraNet's internal labour better reflects these labour costs during the 2013–18 regulatory control period.

The Australian Bureau of Statistics (ABS) has previously advised:

> ...regardless of the type of job, if the job was selected from a business classified to the electricity, gas, water and waste services industry, the job pay movements contributes to this industry.[121]

The ABS takes into account the nature of the business, not the nature of the work undertaken, when allocating a job to an industry. The ABS labour price statistics for the EGWWS industry reflects all general internal labour.

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[120] NER, clause 6A.6.6(c).
[121] ABS, *Email from Kathryn Parlour to Fleur Gibbons*, 8 July 2010.

Since late 2009, the ABS has reported average weekly ordinary time earnings (AWOTE) and LPI data under the ANZSIC[122] 2006 industry classification, where waste services have been included with the EGW industries, producing an EGWWS industry data series. This replaces the ANZSIC 1993 classification which discontinues the publication of the EGW industry data series.

BIS Shrapnel stated the inclusion of the waste services sub-sector in the classification has lead to lower wage growth outcomes for the combined EGW and Waste Services industry.[123] Hence, it is not an accurate indicator for the mostly higher skilled (and more highly demanded) occupations in the EGW sector. Consequently BIS Shrapnel estimated the waste services component and excluded it from both its historical data and forecasts, thus deriving an EGW estimate.

ElectraNet's proposed labour cost escalation rates are based on BIS Shrapnel forecasts for the EGW industry rather than the EGWWS industry used by the ABS. BIS Shrapnel noted that between 1998 and 2009 the LPI for the EGW industry grew by 4.3 per cent per annum as compared to 4.2 per cent for the EGWWS industry.[124]

The AER does not consider that BIS Shrapnel's reasons for excluding the waste service component (that it would result in a lower wage growth) are sufficient to adjust the EGWWS data. Removing the waste services component from the data introduces a potential source of forecasting error since it is necessary to estimate the waste services component. Further, there is likely to be forecasting errors in applying the discontinued EGW industry data series which concluded in June 2009 when the ABS moved to the ANZSIC 2006 classification. This forecasting error will be magnified over time as the period between the last available EGW data (2009) and the forecast period increases.

For these reasons, the AER considers that BIS Shrapnel's use of EGW to escalate labour costs does not reasonably reflect a realistic expectation of labour costs.[125]

DAE has estimated labour costs using the ANZSIC 2006 classification for the EGWWS labour force industry to represent ElectraNet's internal labour force. The AER is of the view that applying forecasts based on the EGWWS industry rather than the EGW most reasonably reflects a realistic expectation of labour costs for ElectraNet's internal labour during the 2013-18 regulatory control period.[126]

Forecast assumptions

The AER considers that the deferral of the Olympic Dam mine expansion means BIS Shrapnel's forecast applied assumptions which are now less accurate. This has caused BIS Shrapnel's forecast to be inflated further than it should. BIS Shrapnel noted its forecast expects a faster wage growth in the South Australia utilities sector.[127] It noted that one of the factors driving this wage growth is the increased demand for skilled workers which will be underpinned by the $27 billion expansion of the Olympic Dam mine.[128]

On 22 August 2012, BHP issued a media release stating:

> ...that it will investigate an alternative, less capital-intensive design of the Olympic Dam open-pit expansion, involving new technologies, to substantially improve the economics of the project. As a result it will not be

122 The Australian and New Zealand Standard Industrial Classification (ANZSIC) provides a framework for organising data about businesses - by enabling grouping of business units carrying out similar productive activities.
123 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, Appendix B, p. A-4.
124 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, Appendix B, Table B-1: EGW V. EGWWS, p. A-4.
125 NER, clause 6A.6.6(c).
126 NER, clause 6A.6.6(c)(3).
127 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, p. ii.
128 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, p. 23.

> ready to approve an expansion of Olympic Dam before the Indenture agreement deadline of 15 December 2012.[129]

The AER notes BIS Shrapnel released its labour cost escalation forecasts in April 2012. Consequently BIS Shrapnel did not have the opportunity to factor the information released by BHP into its forecasts. Therefore, the AER considers BIS Shrapnel's forecast as less likely to be accurate as it included the entire expansion of the Olympic Dam mine. Due to this uncertainty, the AER considers BIS Shrapnel's forecast does not reasonably reflect a realistic expectation of cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.[130]

In comparison the AER considers DAE's forecast an appropriate forecast. At the time DAE submitted its forecast, it stated the Olympic Dam mine had not been factored into its forecasts due to the recent decision issued by BHP not to expand the Olympic Dam mine in the near future.[131] Thus, the AER considers the DAE forecast is more robust and reasonably reflects a realistic expectation of cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.[132]

Adjusted versus unadjusted productivity forecasts

The AER considers that in theory productivity adjustments should be applied to real cost escalations if productivity adjustments are not undertaken elsewhere in opex and capex forecasts. However the high degree of difficulty in estimating quality adjusted labour productivity estimates does not give the AER the ability to make this adjustment with an appropriate level of certainty.

The AER acknowledges ECCSA's considerations that productivity adjustments be applied to ElectraNet's forecast labour costs.[133] Thus, while the AER expects worker productivity to improve over the long run, due to estimation difficulties, it has not sought to address this effect in ElectraNet's forecasts of labour costs.

Use of negotiated wage rate agreements

The AER accepts the use of ElectraNet's EA to escalate internal labour costs. ElectraNet proposed to escalate its internal labour costs using its current EA[134] until it expires in June 2015.[135] BIS Shrapnel's forecast LPI unadjusted for productivity was proposed for the remainder of the 2013–18 regulatory control period.

Generally, the AER has concerns with the use of EAs to set real labour cost escalation as it may not reasonably reflect a realistic expectation of cost inputs required to achieve the opex and capex objectives.[136]' This view is supported by ECCSA who stated it:

> ... does not consider that a regulator should adjust costs to reflect future cost changes that have been negotiated by a single firm. This does not necessary reflect an efficient outcome and provides a bias towards higher labour costs than might occur under a more independent approach.[137]

129 BHP Billiton, *Investors and Media, Latest News: Olympic Dam update*, 22 August 2012.
130 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
131 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 15 October 2012, Executive Summary, p. iii.
132 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
133 ECCSA, *ElectraNet SA Application: A response by the Energy Consumers Coalition of SA*, August 2012, p. 16.
134 ElectraNet Enterprise Agreement 2012, March 2012, p. 8 clause 1.7.
135 ElectraNet, *Revenue proposal 1 July 2013 — 30 June 2018*, 31 May 2012, p. 68.
136 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
137 ECCSA, *ElectraNet SA Application: A response by the Energy Consumers Coalition of SA*, August 2012, p. 16.

The AER took the following steps to test whether ElectraNet's EA is reflective of the efficient and prudent costs given ElectraNet's circumstances. The AER:

- considered ElectraNet's historical collective wage agreements;
- tested ElectraNet's EA against the expert's forecasts; and
- tested ElectraNet's EA against the market.

Historical wage collective agreements

To understand how the new EA compares to historical collective wage agreements the AER undertook an analysis of these outcomes since 2004. The ElectraNet Enterprise Agreement 2012 was approved by Fair Work Australia on 6 March 2012 and replaces the previous ElectraNet Collective Agreement 2007. Table 1.3 shows the new EA provides for an annual 4.5 per cent increase in base wages that is consistent with wage agreement increases over the past 10 years.

Table 1.3 ElectraNet collective wage increases (per cent, nominal)

Agreement	Annual wage increase (per cent)
ElectraNet Enterprise Bargaining Agreement 2004	4.5
ElectraNet Collective Agreement 2007	4.5
ElectraNet Enterprise Agreement 2012	4.5

Source: Fair Work Australia website.

Table 1.3 demonstrates that ElectraNet's collective wage negotiations have remained unchanged even though the South Australian environment for wages has fluctuated over the last decade.[138] Based on the analysis of South Australia's environment for wages over the last decade, the AER has cause to consider whether ElectraNet's EA should have been lower when wage growth in South Australia has been at a lower level.[139] However, the AER considers at the time ElectraNet entered into its current EA, ElectraNet expected to compete for labour in a mining boom. It is therefore not unreasonable for ElectraNet's EA to be higher due to the likelihood forecast projects such as the expansion of the Olympic Dam mine. The AER considers ElectraNet's circumstances when entering into its current EA needs to be taken into consideration when assessing whether it reasonably reflects a realistic expectation of labour costs.[140]

Comparison of ElectraNet's EA with expert forecasts and comparable EAs

The AER undertook further informative analysis to better understand the circumstances of ElectraNet's EA. Table 1.4 compares ElectraNet's EA against BIS Shrapnel's forecast and DAE's forecast as well as collective wage agreement outcomes of the other regulated NSP's in South Australia.

[138] Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 15 October 2012, p. 45.
[139] Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia,* 15 October 2012, p. 44.
[140] NER, clause 6A.6.6(c)(3).

Table 1.4 Comparison of non—productivity adjusted LPI with collective wage agreements (per cent, nominal)[141]

	2009-10	2010–11	2011–12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
ElectraNet[142]	4.5	4.5	4.5	4.5	4.5	4.5			
Envestra/APA[143]	4.5	4.5	4.0	4.0	4.0				
SA Power Networks[144]	4.5	4.5	5.0	4.5	4.5				
BIS Shrapnel	4.3	4.3	4.2	4.6	5.2	5.0	4.8	5.0	5.3
DAE			3.4	3.4	3.6	3.7	3.7	3.6	3.6

Source: EBA's from Fair Work Australia website; BIS Shrapnel, *Labour cost escalation forecasts to 2017–18 — Australia and South Australia*, April 2012; Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia,* 15 October 2012.

Table 1.4 shows ElectraNet's EA is comparable to the other regulated NSPs in South Australia. It also shows the EA is above the DAE and slightly above BIS Shrapnel forecasts to 2012–13 but lies within the two forecasts between 2012–13 to 2014–15.

The AER has already established it is not satisfied that BIS Shrapnel's use of EGW industry data for its forecast reasonably reflects a realistic expectation of labour costs.[145] The AER also notes that BIS Shrapnel's forecast includes the assumption of the Olympic Dam mine expansion and the DAE forecast does not. Therefore the significance of including the Olympic Dam mine expansion can in part be seen in the difference between the two expert forecasts.

The AER acknowledges the circumstances of ElectraNet particularly at the time the EA was entered into.[146] The current EA was formalised in March 2012 and at the time would have factored in the forecast environment and risks to attract and retain staff over the existence of the EA. Given BHP announced the deferral of the Olympic Dam mine expansion in August 2012, ElectraNet (like BIS Shrapnel) would not have been able to have taken this into consideration. Thus the AER considers it reasonable for ElectraNet's EA to be above DAE's forecast.

Table 1.4 further demonstrates that ElectraNet's collective wage agreements have been consistent with those of the other NSPs in South Australia which range annually from 4 to 5 per cent. The AER considers this consistency in recent times was driven by competition for labour between NSP's as well as mining and other related industries. As with ElectraNet, at the time the other NSPs current

141 For industry comparison purposes, the AER have investigated SA Water Corporation's current EA of non-productivity adjusted LPI with collective wage agreements, However, SA Water's current EA does not offer a collective bargaining annual percentage increase which would therefore mean that SA Water use different category escalators and cannot be a reasonable comparator for the purposes of the AER's test.

142 ElectraNet's enterprise agreement pay increases changed from occurring on financial years to calendar years on 1 January 2012. Therefore, as proxy, the pay increases from the 2012–13 financial year onwards represent the pay increase of the January immediately before 1 July of that year.

143 On 2 July 2007, APA Asset Management was appointed the major subcontractor to Envestra. It operates, maintains and extends the Envestra South Australian gas distribution networks. The EBA's used in this analysis are therefore those of APA Asset Management. The annual increase occurs on 1 September. Therefore, as a proxy, the pay increases for each financial year represent the pay increase of the September immediately after 1 July of that year.

144 SA Power Networks was formerly known as ETSA Utilities.

145 NER, clause 6A.6.6(c)(3).

146 NER, clauses 6A.6.6(c)(2) and 6A.6.7(c)(2).

collective wage agreements were entered into the wage growth forecasts were expected to be higher given the economic outlook (particularly the impact of mining).[147] Based on a comparison against its peers ElectraNet's current EA appears reasonable. However, the AER considers that future collective wage agreements in South Australia should be lower given the lower wage growth predicted.[148]

Following the AER's consideration of ElectraNet's historical collective wage agreements; its EA against the expert's forecasts and against the market the AER accepts the use of ElectraNet's EA to forecast its internal labour costs until it is due to expire June 2015.[149] However, the AER notes that given the change in circumstances, BIS Shrapnel did not have the opportunity to exclude the expansion of the Olympic Dam mine in its forecasts. Therefore the AER considers that BIS Shrapnel's forecasts are now less reliable due to the inclusion of a major project in its forecasts that has now been postponed. Therefore post June 2015 the AER considers the DAE forecast should be applied to escalate ElectraNet's internal labour.

External labour cost escalation

ElectraNet also proposed forecast LPI unadjusted for productivity in the construction sector for its external labour cost escalation.[150] The AER agrees with this proposed forecast for escalating external labour costs. However, the AER does not accept ElectraNet's proposed escalators. As established, the AER considers BIS Shrapnel's forecasts to be inflated further than necessary as it had factored in the expansion of Olympic Dam mine.[151]

BIS Shrapnel noted that construction activity in South Australia declined in 2010–11 due to the completion of several publicly funded construction projects.[152] However, it further noted that this decline would be short lived due to the start of the Olympic Dam mine expansion in late 2012. BIS Shrapnel noted:[153]

> The size of this project will overshadow construction activity across the other sectors and lead total construction activity to record exceptionally strong growth over 2012/13 and 2013/14 and stabilise at these high levels over the three years to 2017/18.

This major project has now been postponed. Thus, the AER considers BIS Shrapnel's forecast does not reasonably reflect a realistic expectation of cost inputs required for the 2013-18 regulatory control period.[154]

In comparison the AER considers DAE's forecast of LPI unadjusted for productivity for the South Australian construction industry to be an appropriate forecast. DAE's construction wages growth forecast for South Australia does not include the expansion of the Olympic Dam mine.[155] Thus, the AER considers the DAE forecast reflects a realistic expectation of cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.[156]

1.4.2 Material escalators

The AER accepts ElectraNet's proposed weighted average material escalator method. ElectraNet has undertaken reasonable steps to provide accurate inputs and weightings reflective of the requirements

147 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 15 October 2012, pp. 44–5.
148 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 15 October 2012, p. 41.
149 ElectraNet, *Revenue proposal 1 July 2013 — 30 June 2018*, 31 May 2012, p. 68.
150 ElectraNet, *Revenue proposal 1 July 2013 — 30 June 2018*, 31 May 2012, pp. 68–70.
151 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, p. 53.
152 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, p. 53.
153 BIS Shrapnel, *Labour Cost Escalation Forecasts*, April 2012, p. 53.
154 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
155 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 15 October 2012, p. 85.
156 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).

for its proposed total forecast capex. However, the AER does not accept the proposed escalation rates and has updated ElectraNet's forecast inputs for the latest available data and conversion rates. The AER will again update the inputs closer to the final decision in 2013.

ElectraNet included a weighted average material escalation for the 2013–18 regulatory control period in its revenue proposal.[157] Table 1.5 shows ElectraNet's proposal and the AER's draft decision.

Table 1.5 Weighted average material annual escalation (per cent, real)

Annual escalation	2013–14	2014–15	2015–16	2016–17	2017–18
ElectraNet proposal	2.1	1.7	1.5	1.7	1.9
AER draft decision	2.2	1.2	0.3	0.6	0.9

Source: AER analysis, ElectraNet, *Revenue proposal*, p. 72.

ECCSA raised concerns regarding real cost escalation for only one, or some, materials as a proxy for the entire basket of network materials escalation. [158] This is because an input cost model uses the cost of inputs, and the proportions in which they are used, to predict the price of an end product. It is difficult to determine whether the change in price of an input necessarily means the price of related outputs will increase. There may be many causal factors that drive output prices such as the substitution of cheaper alternatives. Also forecasts can be upwardly biased when a proposed material escalation only accounts for the items that are increasing and not the items that are decreasing.

The AER notes that ElectraNet's input cost model provides weightings based on the actual proportion of its inputs for each particular cost category of capex. For example, a cost category which has large proportions of copper and crude oil are deescalating over the 2013–18 regulatory control period. Thus the AER considers ElectraNet's method reasonable. As demonstrated in Table 1.2, ElectraNet has included both items for which prices are forecast to increase but also items for which prices are forecast to decrease.

The AER notes ElectraNet's material prices and indices were calculated in $US and converted into $AUD.[159] This is because the majority of materials are either produced in $US or in currencies that are significantly influenced by the $US. The AER considers this a reasonable method and has updated the forecast currency conversions for the latest data. Table 1.6 shows ElectraNet's proposed exchange rate forecast and the AER's updated exchange rate forecast for the draft decision.

Table 1.6 Australian dollar to US dollar exchange rate forecast ($AUD)

$AUD–$US exchange rate	2013–14	2014–15	2015–16	2016–17	2017–18
ElectraNet proposal	0.98	0.95	0.92	0.89	0.87
AER draft decision	1.00	0.97	0.94	0.92	0.90

Source: AER analysis, ElectraNet, *Revenue proposal*, p. 72; CEG, *A report for ElectraNet*, May 2012, p. 12.

157 ElectraNet, *Revenue proposal*, pp. 68–70.
158 ECCSA, *ElectraNet SA application: A response by the Energy Consumers Coalition of SA*, August 2012, pp. 18–20.
159 ElectraNet, *Revenue proposal*, pp. 68–70.

The AER has updated ElectraNet's forecast inputs for the latest data and conversions rates as shown Table 1.1. The impact of this is a reduction to ElectraNet's proposed weighted average material escalation for the 2013–18 regulatory control period.

1.4.3 Land value escalation

The AER accepts ElectraNet's proposed singular land value escalator (total land) be applied as an input to the weighted average material escalator. However, the AER does not accept ElectraNet's proposed total land value escalator be applied as the sole escalator to its proposed forecast land and easement capex and land tax model. The AER considers this does not reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[160]

ElectraNet proposed the total land value escalator be applied both as an input into its weighted average material escalator but also as the escalator for its proposed forecast land and easement acquisitions and land tax model.[161] Land value escalation is to account for the cost of acquiring land in the future. It is applied as an input into the weighted average material escalator as some augmentation, replacement and security/compliance capex projects contain elements of land and easements. It is also applied as the escalator for forecast land and easements capex and for future land tax purposes.

Land value escalation for forecast land and easement acquisitions

The AER does not consider the application of the total land value escalator to all forecast land and easement capex is appropriate as it overstates some future land and easement project capex and land taxes and understates others. A concern shared by ECCSA.[162] The AER considers the data is available to escalate ElectraNet's proposed land and easement projects by a corresponding land type value escalator because the project locations and land types are known. For example, a proposed rural land acquisition should be escalated by the corresponding rural land value escalator. The AER considers that by applying the corresponding land value escalator the forecast is more accurate and reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.[163] Thus the AER rejects ElectraNet's proposed total land value escalator in these instances and substitutes the multiple land type value escalators for the respective proposed land and easement acquisition capex. Table 1.7 shows these multiple land type value escalators.

160 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
161 ElectraNet, *Revenue proposal*, pp. 70–72.
162 ECCSA, *ElectraNet SA application: A response by the Energy Consumers Coalition of SA*, August 2012, pp. 17–18.
163 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).

The AER considers Maloney Field Services used an appropriate data source on which to forecast future land values. However, the AER notes that the available time series extends out to June 2011 and not June 2010 as per the Maloney Field Services analysis. Thus the AER has updated this analysis in to include the full time series of data available.

Table 1.7 Land value escalation factors for land and easement acquisition capex and land tax (per cent)

Land value index	Maloney Field Services Average annual increase (June 1989—June 2010)	AER draft decision Average annual increase (June 1989—June 2011)
Residential land	10.7	10.6
Commercial land	8.1	7.9
Rural land	7.6	7.4
Other land	7.7	8.4

Source: AER analysis; ABS, *5204 Australian System of National accounts publication 2010–11*; ElectraNet, *Revenue proposal*, p. 71; Maloney Field Services, May 2012, p. 3.

Land value escalation as an input for material escalators

The AER accepts ElectraNet's approach to include the total land value escalator as an input to the weighted average material escalator. For the remaining capex categories, such as security/compliance, the land types are not as easily distinguishable. In addition, the overall impact of applying either the total or multiple land type escalators to the weighted average material escalator is immaterial. Thus the AER considers due to the complexity and overall immaterial impact, it is reasonable to use the total land value escalator as an input into the calculation of the weighted average material escalator. The AER again has updated the calculation to accurately reflect the most recent data. Table 1.8. shows the total land type value escalator.

Table 1.8 Land value escalation factors (per cent, nominal)

Land value index	Maloney Field Services Average annual increase (June 1989—June 2010)	AER draft decision Average annual increase (June 1989—June 2011)
Total land	9.5	9.4

Source: AER analysis, ABS, *5204 Australian System of National accounts publication 2010–11*, ElectraNet, *Revenue proposal,* p. 71, Maloney Field Services, May 2012, p. 3.

The AER has updated ElectraNet's forecast inputs for the latest data in Table 1.1. The impact of this is a reduction to ElectraNet's proposed land value escalation for the 2013–18 regulatory control period.

1.5 Revisions

Revision 1.1: Table 1.1 sets out the AER's substitute real cost escalators for the 2013–18 regulatory control period.

2 Demand

This attachment sets out the AER's consideration of ElectraNet's proposed demand forecast for the 2013–18 regulatory control period.[164] The expected growth in peak electricity demand is an important factor driving network augmentation and connection point capex projects (load driven capex). Demand forecasts are used in conjunction with network planning to determine the amount and timing of load driven expenditure. ElectraNet relied on SA Power Networks' connection point forecasts in determining its total capital expenditure (capex) forecast for the 2013–18 regulatory control period. ElectraNet's load driven capex comprises approximately 28 per cent of ElectraNet's forecast capex.

The AER engaged Energy Market Consulting associates and NZIER (EMCa) to advise on ElectraNet's demand forecast and forecasting method.

2.1 Draft decision

The AER considers ElectraNet's demand forecast is not a realistic expectation of demand for the 2013–18 regulatory control period. Table 2.1 sets out the AER's alternative demand forecast. The changes are material and have a significant impact on capex. Thus, ElectraNet's load driven capex forecast does not meet the alternative demand forecast. In turn, ElectraNet's load driven capex does not meet the capex criteria.[165]

Table 2.1 AER's draft decision on ElectraNet's demand forecast

	2013-14	2014-15	2015-16	2016-17	2017-18
ElectraNet forecast (MW)	4077	4200	4321	4443	4553
AER forecast (MW)	3644	3721	3797	3872	3928
Difference (MW)	433	479	524	571	625
Difference (%)	10.7	11.4	12.1	12.9	13.8

Sources: ElectraNet, *Revenue proposal,* appendix J; EMCa analysis.

2.2 ElectraNet's proposal

ElectraNet forecast an average annual increase in demand of 3.0 per cent over the 2013–18 regulatory control period.[166] ElectraNet attributes this increase in demand to the:[167]

- positive economic outlook in the medium to longer term
- real prospect of significant new mining industry loads.

ElectraNet does not rely on the Australian Energy Market Operator's (AEMO) forecasts for capex planning purposes. Rather, ElectraNet's total forecast capex is derived from two classes of connection point demand forecasts. Namely:

- SA Power Networks' connection point forecasts—these make up the bulk of ElectraNet's forecast demand; and

164 In this attachment, demand refers to summer peak demand (megawatts, MW) unless otherwise indicated.
165 NER, clause 6A.6.7(c).
166 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, pp. 7 and 10.
167 ElectraNet, *Revenue proposal*, p. 31.

- ElectraNet's own direct connect customers—direct connect customers are customers who usually require a large electricity load and therefore connect directly to ElectraNet's transmission network at a specific connection point.

ElectraNet stated that it uses AEMO's forecasts to plan main grid augmentations, as well as main grid reactive requirements, which are driven by total demand levels across the network. It also stated that AEMO state wide forecasts are diversified, which means that they reflect the fact that peak demand does not occur simultaneously at each connection point on the network at the time of system peak demand. For this reason, ElectraNet uses SA Power Networks' connection point forecasts for connection point and local regional planning.[168]

ElectraNet's revenue proposal describes a state wide demand forecast which it attributed to the AEMO 2011 South Australian supply and demand outlook (SASDO).[169] This led stakeholders, such as the South Australian Council of Social Service (SACOSS) to make submissions on the appropriateness of AEMO's 2011 demand forecast.[170] However, as Electranet did not base its capex forecast on AEMO's 2011 forecast, some submissions were ultimately based on irrelevant information.

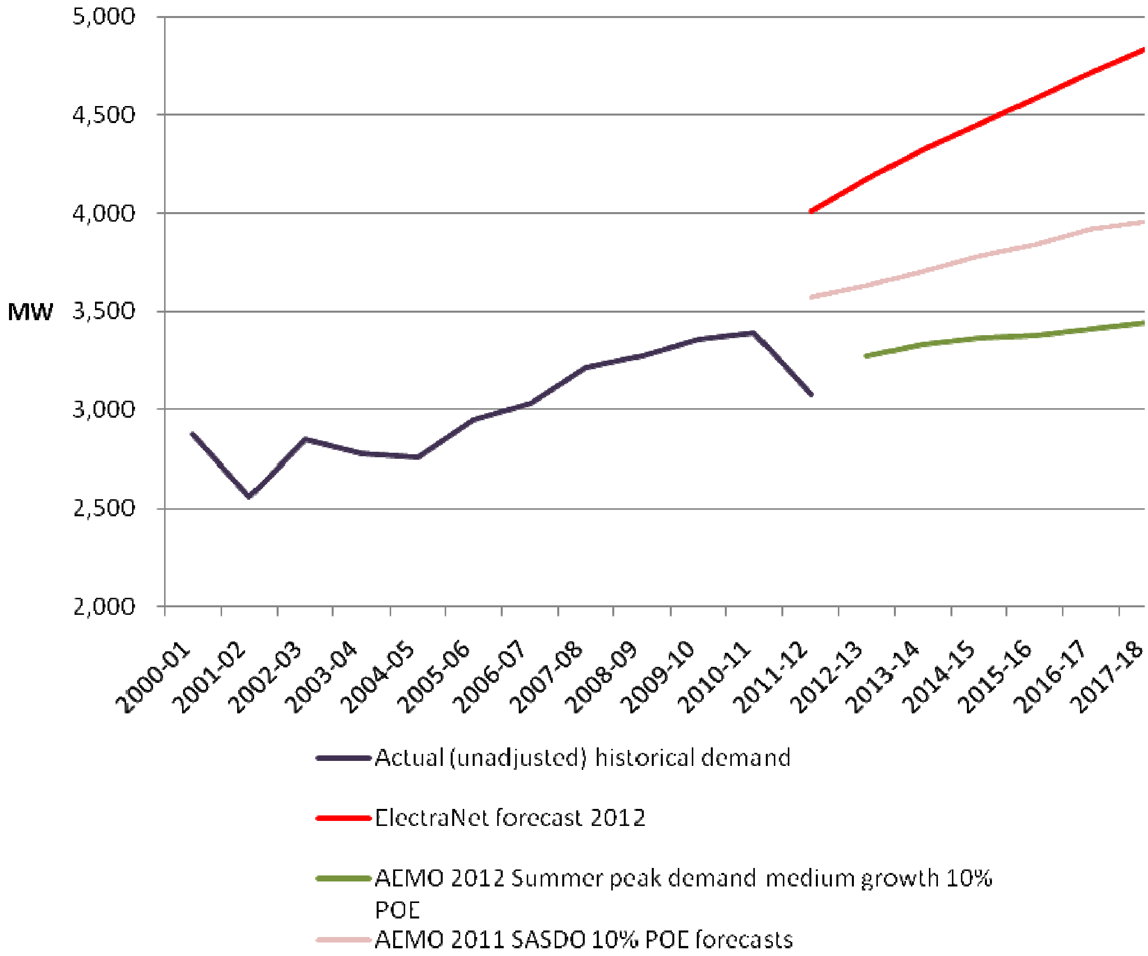
ElectraNet based its demand forecast on SA Power Networks' 2012 connection point demand forecasts. However, its revenue proposal did not describe the method used by either it or SA Power Networks in determining its connection point demand forecast.

ElectraNet provided the AER with a report that set out SA Power Networks' 2011 demand forecasting method.[171] The report described SA Power Networks' forecasting method and how ElectraNet reconciled its 2011 bottom up connection point demand forecast with AEMO's 2011 top down state wide demand forecast.[172] The AER understands SA Power Networks applied the forecasting method described in the report to produce its 2012 forecast. Therefore, the AER referred to this report to assess how SA Power Networks produced its 2012 demand forecast. ElectraNet also provided further information on its and SA Power Networks' demand forecasting method when responding to specific requests for information.

Figure 2.1 shows ElectraNet's historical demand during the period 2000–01 to 2012–13, AEMO's 2011 and 2012 forecasts and ElectraNet's forecast as set out in appendix J to its revenue proposal.[173]

168 ElectraNet, *Revenue proposal*, p. 64.
169 AEMO, *South Australian supply and demand outlook*, 2011.
170 SACOSS, *Submission to the Australian Energy Regulator consultation on ElectraNet's 2013-18 transmission network Revenue proposal*, August 2012, p. 3.
171 ElectraNet, *Demand forecast reconciliation report,* ENET068*,* 7 June 2012 [public version].
172 AEMO, *South Australian supply and demand outlook*, 23 June 2011.
173 ElectraNet, *Connection point peaks*, response to EMCa RP, ENET221, 2 August 2012 [confidential]: data for the actual unadjusted historical demand was aggregated from data provided by ElectraNet.

Figure 2.1 Comparison of AEMO's and ElectraNet's demand forecast



Sources: ElectraNet, *Connection point peaks*, ENET221, 2 August 2012 [confidential]; ElectraNet, *Revenue proposal,* appendix J, AEMO, *SASDO,* 2011; AEMO, *National electricity forecasts* 2012.

ElectraNet's demand forecasting method

ElectraNet uses SA Power Networks' 2012 'bottom up' connection point undiversified peak load demand forecasts and direct connect transmission customer forecasts for its regional and connection point augmentation and planning. Connection point peak demand forecasts are projections of the maximum electricity demand expected at each connection point or bulk supply point in the future.

SA Power Networks' demand forecasting method did not account for diversity of peak demand across its connection points and regions.[174] Further, ElectraNet did not apply a diversity factor to SA Power Networks' connection point demand forecasts in producing its regional forecasts.

ElectraNet stated it does not adjust SA Power Networks' connection point forecasts[175] because it must meet the reliability standards under the Electricity Transmission Code (ETC)[176] that are set by reference to SA Power Networks' demand forecast.[177]

[174] ElectraNet, *Revenue proposal*, p. 64.
[175] ElectraNet, *Revenue proposal*, p. 64 and appendix J.
[176] ETC, TC/07, effective 1 July 2013.

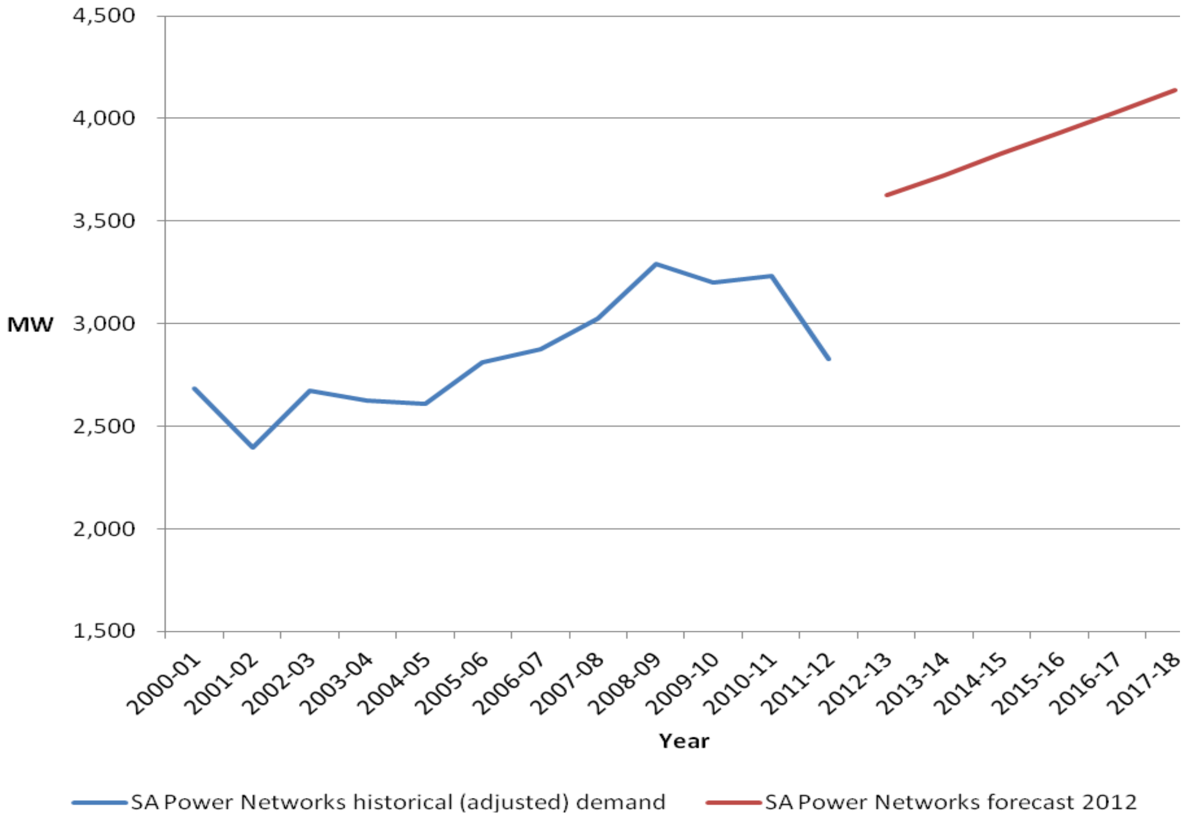
ElectraNet aggregates SA Power Networks' data by region and uses that data to model regional load flows for forecasting regional augmentation capex.

ElectraNet assumed a diversity factor of 1.0, that is, unity of peak demand for the connection points and for each region. It did so on the basis that the driver for peak events (such as heat waves) affects all connection points simultaneously. Its approach also assumed no diversity within a region for other reasons, such as, diversity between connection points that feed residential loads and those that feed commercial and industrial loads.ElectraNet did not reconcile SA Power Networks' 2012 forecast with a top down forecast such as AEMO's 2012 state wide demand forecast.[178] It provided a reconciliation of its 2011 forecasts with AEMO's 2011 forecasts,[179] but its proposal is not based on AEMO's 2011 forecast, which is now outdated.[180]

SA Power Networks' demand forecasting method

Figure 2.2 shows SA Power Networks' 2012 connection point forecast in undiversified form compared with the historical peak demands for the last 10 years.[181]

Figure 2.2 SA Power Networks' undiversified historical peak demand and planning forecast



Source: ElectraNet, *Revenue proposal*, appendix J; ElectraNet, *Summary CP historical and forecast peaks*, ENET0063, June 2012 [confidential]; ElectraNet, *Connection point peaks,* ENET221, 2 August 2012 [confidential]; ElectraNet*, Response to EMCa041 - Peak Load Data (Revised),* ENET244, 29 August 2012 [confidential].

177 ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, p. 4.
178 AEMO, *National electricity forecasting report*, 2012, p. 6.10.
179 ElectraNet, *Load forecast reconciliation,* ENET068, 7 June 2012.
180 AEMO, *National electricity forecasting report*, 2012, p. 6.10.
181 ElectraNet, *Revenue proposal*, appendix J.

SA Power Networks' determined its demand forecast from two historical data points:[182]

- peak demand from 2009
- peak demand from 2001 adjusted upwards to a temperature equivalent to 2009's peak demand.

The 2009 peak is the summer peak of 3490 MW that occurred in extreme heatwave conditions. The 2001 peak is an adjusted peak that occurred in heatwave conditions in 2001.

SA Power Network adjusted the 2001 peak upwards by a temperature correction factor of 1.4 per cent to reflect the higher temperatures during the 2009 extreme heatwave compared with the 2001 heatwave. The temperature correction factor represents a notional increase in peak demand for 2001 to place it on the same footing as if the temperatures in both years had been equivalent. ElectraNet's demand forecast is not based on a probabilistic planning model.

SA Power Networks then added back into the historical data, assumed values for demand side participation and embedded generation.[183] It also added spot load increases to the projected peaks where it considered these to be of sufficient size and certainty not to be reflected in the business-as-usual growth rate. It also adjusted the forecasts to reflect anticipated load transfers between connection points and any large committed disconnections.[184]

SA Power Network used the 2009 peak demand as the base year for its demand forecast projection. It then used the average percentage growth rate that applied between the (adjusted) 2001 peak and 2009 peak to project the peak demand growth rate forward. It applied this method at each connection point.

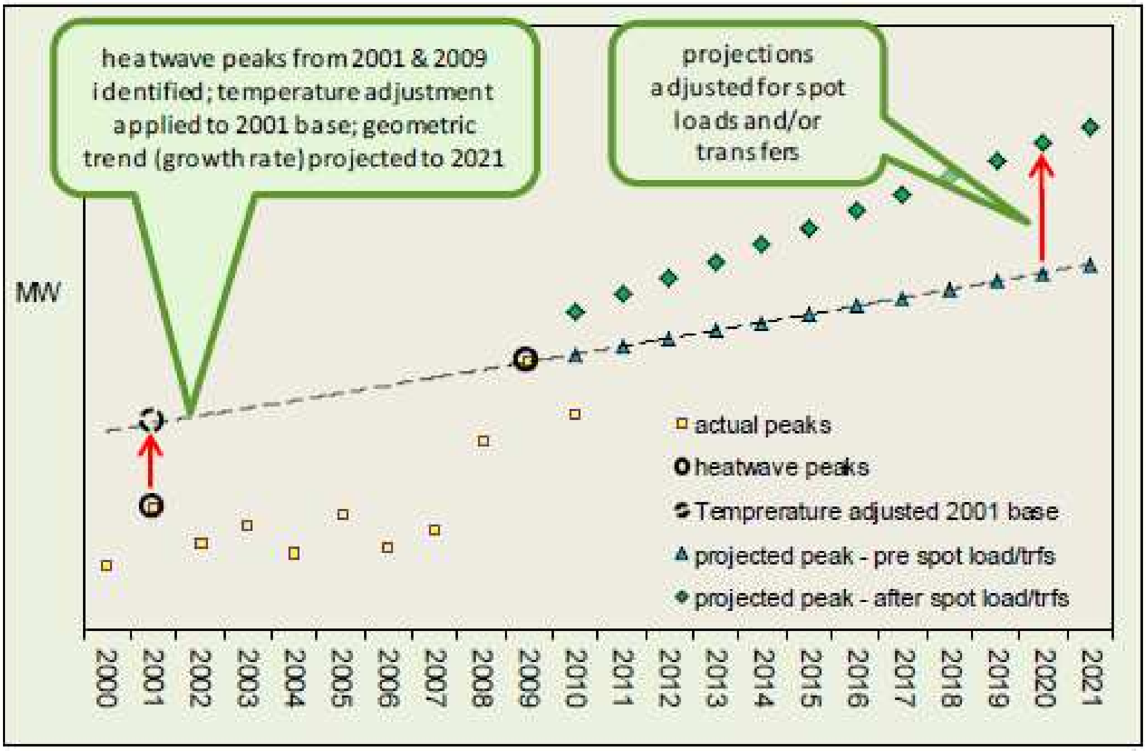
Figure 2.3 shows the peak-to-peak extrapolation method and the adjustments to historical demand that SA Power Networks used to determine its demand forecast.

182 ElectraNet, *Load forecast reconciliation,* ENET068, 7 June 2012, pp. 37 and 39 [public version].

183 Demand side participation is where a customer reduces its energy requirements at times of peak demand, usually by agreement with the TNSP. Embedded generation means electricity that is generated by sources in the network such as household roof top photovoltaic generation.

184 ElectraNet, *Load forecast reconciliation*, ENET068, 7 June 2012, pp. 37 and 39 [public version].

Figure 2.3 SA Power Networks' demand forecasting method



Notes: The first red arrow represents the upward correction to actual demand in 2001 when actual temperature was lower than the extreme temperature conditions of 2009. It shows the upward adjustment to demand for the 2001 peak at a temperature less than the temperature equivalent in 2009.

Source: ElectraNet, *Load forecast reconciliation,* ENET068, 7 June 2012, p. 40 [public version].

2.3 Assessment approach

The AER must be satisfied that ElectraNet's forecast capex reasonably reflects the capex criteria. In particular, ElectraNet's total forecast capex must reflect a realistic expectation of demand. If the AER is not satisfied it must not accept ElectraNet's forecast and must use a substitute forecast capex.[185] The AER engaged EMCa to advise on ElectraNet's demand forecast.

The AER anticipated that ElectraNet would rely upon AEMO's demand forecasts for the purpose of developing its revenue proposal. The AER set EMCa's original terms of reference on the understanding that AEMO was to work with ElectraNet in developing its network augmentation capex proposal and the underlying demand forecasts. The AER considers it prudent and appropriate to limit the scope of its technical consultant's review to a high level only, when reviewing matters that AEMO is to review. This results in a targeted approach.

In the early stages of EMCa's assessment it became clear that ElectraNet did not rely on AEMO's 2011 demand forecasts when forecasting capex. Rather, ElectraNet used SA Power Networks' load forecasts at connection point and regional level. These forecasts together with ElectraNet's direct customer forecasts are contained in appendix J to the revenue proposal.[186]

On 5 June 2012, the AER received AEMO's review of ElectraNet's 2013–18 revenue proposal. The report stated that AEMO had reviewed ElectraNet's proposal including its proposed network augmentation projects. AEMO based its review on SA Power Networks' 2012 demand forecast as

185 NER, clauses 6A.6.7(d) and (f).
186 ElectraNet, *Revenue proposal*, appendix J.

proposed by ElectraNet. AEMO specifically did not review either ElectraNet's or SA Power Networks' connection point forecasts.[187]

As a result, the AER amended EMCa's terms of reference to allow it to focus its assessment on SA Power Networks’ connection point demand forecasts which comprise the majority of ElectraNet's demand forecast. To form a view on ElectraNet's demand forecasts, the AER assessed:

- ElectraNet's demand forecasting method, including:
  - ElectraNet's use of SA Power Networks' connection point demand forecast. In particular, the AER focused on SA Power Networks' forecasting method (see section 2.4.1) and considered how SA Power Networks:
    - extrapolated the forecast demand trend from two inputs:
      - a single peak demand that occurred in extreme heatwave conditions in 2009
      - past corrected demand from a peak in 2001.
    - adjusted original historical demand data for a range of matters, including the impact of consumer demand response and embedded generation
    - based its demand forecast on peak demand from 2009, so implicitly, did not account for any changes in demand since 2009. The impact of the significant increase in roof-top photovoltaic generation since 2009 is one such change.
  - ElectraNet's approach to regional and state diversity of maximum demand. ElectraNet assumed no diversity existed at the connection points for each region
  - the extent to which ElectraNet accounted for both connection point (bottom up) and state wide econometric (top down) demand information in producing its demand forecast.
- ElectraNet's forecasting performance (comparing past forecasts with actual demand):
  - while demand forecasting is not a precise science, assessment of forecasting performance can indicate whether ElectraNet's demand forecasts are biased upwards or downwards. Forecasts that are consistently above demand, for example, suggest an upward bias in methods, models or inputs (section 2.4.2).
- the effect of the ETC and ElectraNet's obligation to provide sufficient capacity following changes in forecast agreed maximum demand (section 2.5).

The AER's assessment of ElectraNet's forecast demand relied on various sources including ElectraNet's revenue proposal and responses to information requests, EMCa's analysis and public submissions to the revenue proposal.

In August 2012, AEMO published its electricity report for South Australia.[188] AEMO's forecast indicated a significant drop in demand compared with ElectraNet's forecast.

During the course of the AER's assessment, the AER became aware that both AEMO and ElectraNet were preparing reports reconciling ElectraNet's forecast with AEMO's forecast. The AER expected to receive both reports; however, neither report was available in time for inclusion in this draft decision.

187 AEMO, *ElectraNet revenue cap review*, 2012, p. iv.
188 AEMO, *South Australian electricity report,* 2012.

Given the limited time available, EMCa was asked to undertake a broad-brush review of ElectraNet's connection point forecast only and not a full econometric or other quantitative analysis.

EMCa reviewed ElectraNet's connection point forecast by:

- adjusting the data to a 10 per cent probability of exceedance (POE) estimate
- adjusting the data for regional diversity
- reviewing AEMO's 2012 demand forecasts to provide indicative comparisons on such factors as growth rates, diversity, temperature correction, allowance for photovoltaic installations
- reviewing the basis for ElectraNet's direct connect customer demand forecasts.

2.4 Reasons for draft decision

The AER considers ElectraNet's demand forecast is not a realistic expectation of demand for the 2013–18 regulatory control period.

The AER focused its analysis on SA Power Networks' connection point forecasts as ElectraNet relied on these forecasts in its revenue proposal.[189] Much of the methodology used to produce ElectraNet's demand forecast is therefore SA Power Networks' methodology. The AER considers that the method used to produce ElectraNet's demand forecast:

- did not appropriately consider the uncertainty of temperature fluctuations on peak demand.

  ElectraNet's demand forecast is not based on a temperature related POE such as a 'one in 10 years' event (10 per cent POE). ElectraNet acknowledged the significance of temperature on peak demand and the AER considers a demand forecast should expressly account for temperature uncertainty.

- did not appropriately account for photovoltaic generation, embedded generation, and demand response.

  The AER considers SA Power Networks inappropriately adjusted historical data upwards. SA Power Networks added back significant amounts of consumer demand response and embedded generation that were operating at the time of network peaks. This significantly increased the historical data points on which it based its forecast.

- did not apply a diversity factor when modelling regional forecasts, which is needed to reflect differences in peak demand across the regions.

  SA Power Networks did not account for the diversity of peak demand across its connection points and regions. Further, ElectraNet did not apply a diversity factor to SA Power Networks' connection point data to produce regional demand forecasts. The AER considers a diversity factor should be applied to properly account for differences in peak demand across all regions in the network.

- was not reconciled to a top down econometric forecast.

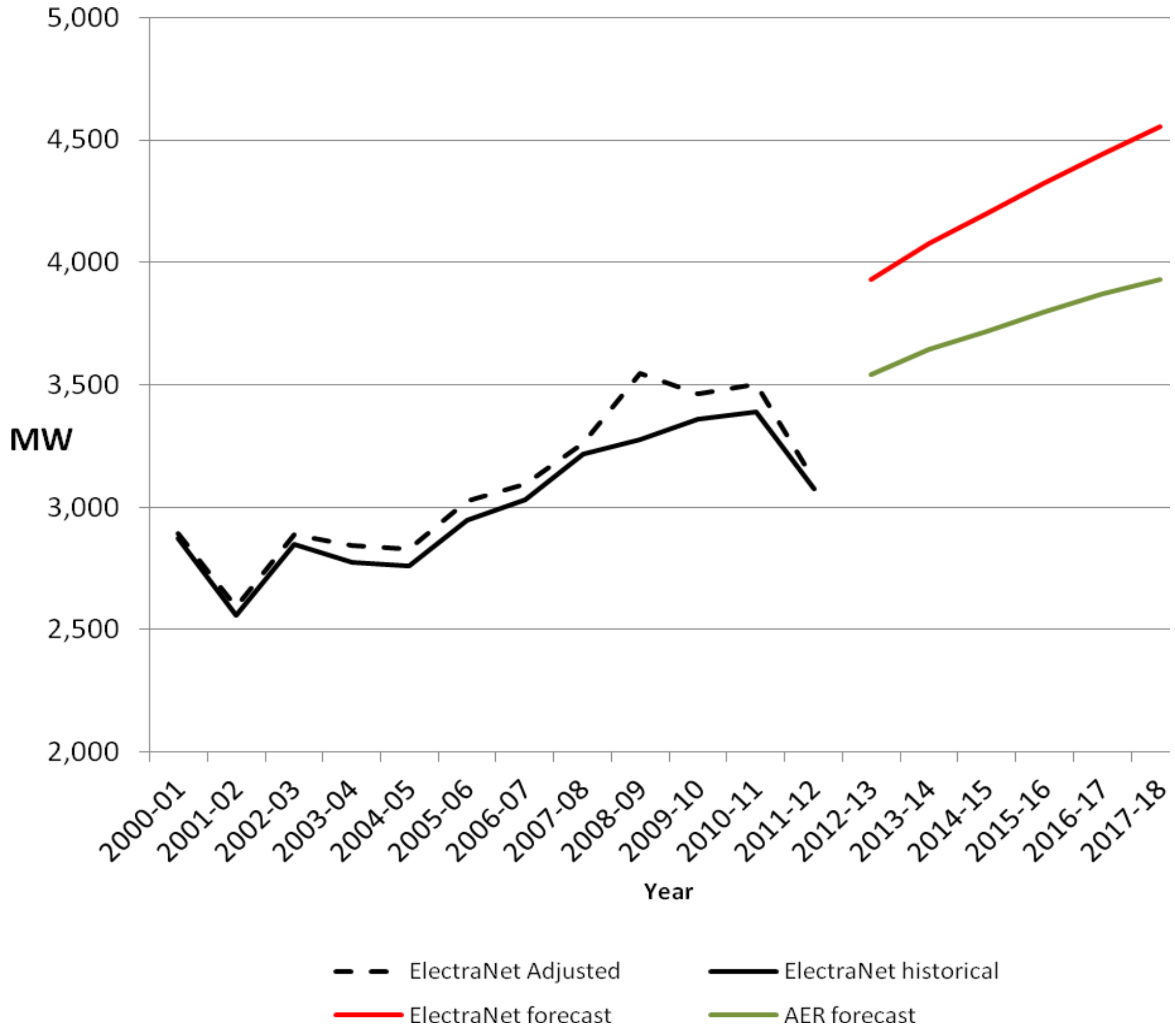
  The AER considers SA Power Networks' method was not robust. SA Power Networks' connection point demand forecast is considerably higher than AEMO's 2012 state wide demand forecast. The AER considers that a sound connection point forecast should be reconciled with a top down

189 ElectraNet, *Revenue proposal*, appendix J.

econometric forecast. ElectraNet did not do this. The AER considers that the failure to include other input sources that reflect a reasonable expectation of conditions relevant to demand produces an upward bias in SA Power Networks' demand forecast.

These factors contributed to the AER not being satisfied that ElectraNet's forecast capex reflected a realistic expectation of demand. The AER considers ElectraNet's forecast is materially different from that of the AER. For the above reasons the AER used a substitute demand forecast to assess whether ElectraNet's total forecast capex reasonably reflects the capex criteria (section 2.6).[190] Figure 2.4 compares ElectraNet's and the AER's demand forecast for the 2013–18 regulatory control period and also shows the actual and adjusted demand between 2000–01 and 2011–12.

Figure 2.4 ElectraNet's and the AER's demand forecasts with ElectraNet adjusted and unadjusted historical demand



Sources: ElectraNet, *Revenue proposal*, appendix J; ElectraNet, *Summary CP historical and forecast peaks*, ENET0063, June 2012 [confidential]; ElectraNet*, Response to EMCa041 - Peak Load Data (Revised),* ENET244, 29 August 2012 [confidential]; ElectraNet, *Connection point peaks,* ENET221, 1 August 2012 [confidential]; ElectraNet*, Revenue proposal,* appendix J; EMCa analysis.

190 NER, clause 6A.7.6(c)(3).

Section 2.4.1 discusses ElectraNet's demand forecasting method in more detail, including SA Power Networks' demand forecasting method. It also discusses ElectraNet's demand forecast in light of AEMO's 2012 South Australian demand forecasts.

Section 2.4.2 compares ElectraNet's past demand forecasts with actual demand. It shows ElectraNet consistently over forecast demand in the 2008–13 regulatory control period.

Section 2.5 discusses ElectraNet's obligations under the ETC to provide sufficient capacity to meet changes in forecast demand.

2.4.1 AER assessment of ElectraNet's demand forecasting method

Indirect versus direct demand forecasting

Figure 2.5 and Figure 2.6 outline two approaches to demand forecasting: direct and indirect demand forecasting, respectively. Direct forecasting models produce demand forecasts (in MW) directly from a given set of inputs. Indirect forecasting models (such as AEMO's) produce energy consumption forecasts (in gigawatt hours, GWh) from a given set of inputs. Factors then transform the energy consumption forecasts into demand forecasts.

Figure 2.5 Direct demand forecasting

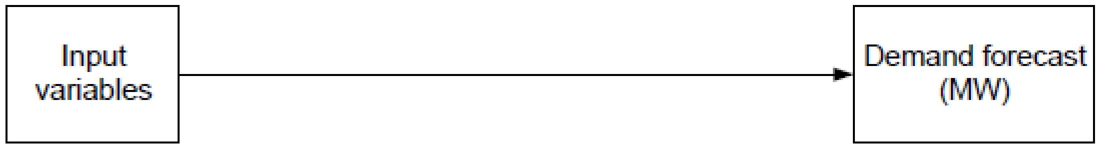
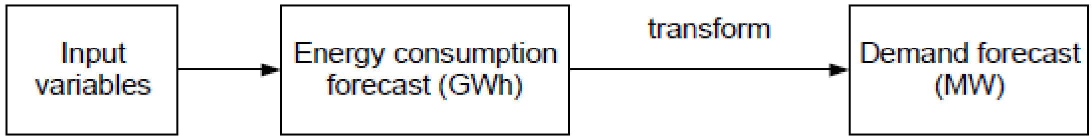


Figure 2.6 Indirect demand forecasting



SA Power Networks’ forecasting method

SA Power Networks' forecasting method may be described as a direct forecast based on a peak-to-peak extrapolation of two data points based on adjusted historical data. The following sections assess each element of SA Power Networks’ forecasting method.

Peak to peak extrapolation

SA Power Networks developed its demand forecast from two historical peaks—peak demand that occurred in 2009 and a notionally adjusted peak that occurred in 2001. It adjusted actual demand in 2001 to the 2009 reference temperature, as shown above in Figure 2.3.

The AER considers SA Power Networks' method is flawed because:[191]

- The 'peak-to-peak' model is compromised by the material adjustments SA Power Networks made to the historical data it used to extrapolate its demand forecast.

[191] EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 23.

- The extrapolation model did not appropriately consider the underlying growth trend present in the historical demand data.

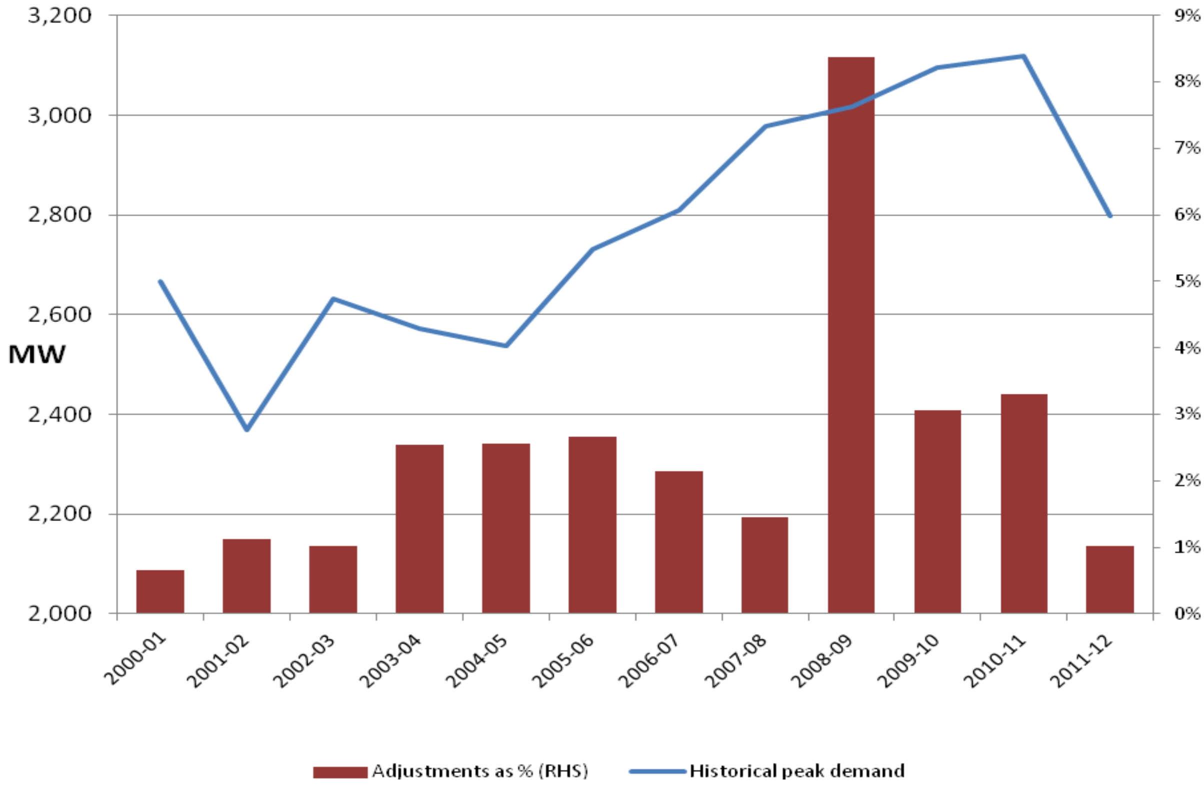
The AER considers that the material adjustments to recent historical demand challenge the appropriateness of SA Power Networks' 'peak-to-peak' forecasting. This is particularly true for the large upward adjustment that SA Power Networks made to create an apparent 2009 'all-time peak'.[192] The AER considers this adjustment compromises both the growth rate (measured between the 2001 and 2009 'adjusted' peaks) and the choice of the 2009 adjusted peak as the base year for the forecast. The AER's position is supported by EMCa's advice.[193]

Adjusted historical data

SA Power Networks adjusted historical demand data upwards for a range of matters, including off-set and spot loads, photovoltaic generation, controlled loads and demand side participation.[194] The adjustments are significant. In particular, SA Power Networks added back significant amounts of consumer demand response and embedded generation that were operating at the time of network peaks. It thus significantly increased the historical data points on which it based its forecast.

Figure 2.7 contains EMCa's analysis of the original actual peak demands from 2001 and the range of the annual adjustments. It shows that the 2009 measured peak demand was adjusted upwards by 8 per cent.

Figure 2.7 SA Power Networks' historical peak demand adjustments



Source: EMCa analysis from data supplied by ElectraNet.

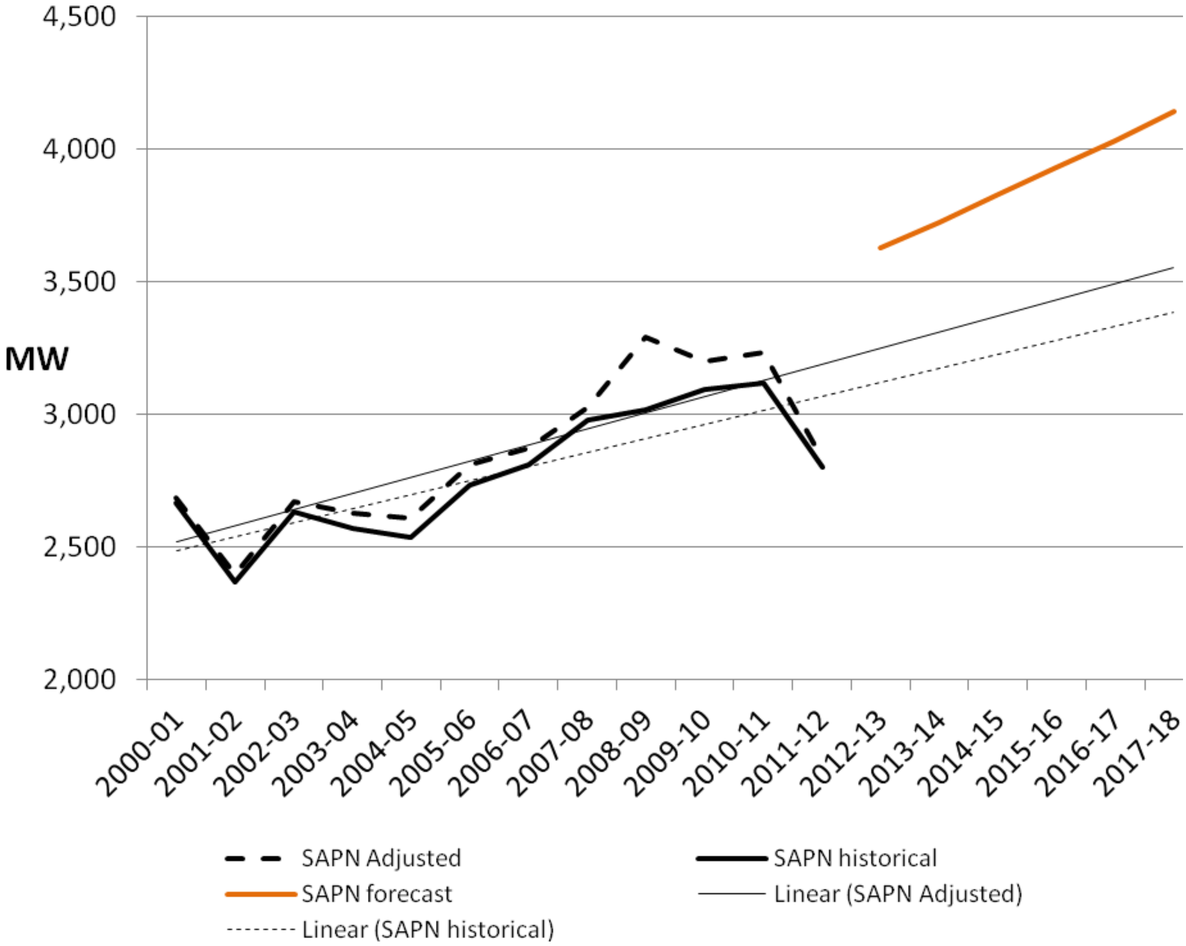
192 Actual all time peak occurred in 2011 - EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 20.
193 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 20.
194 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, pp. 5 and 30.

Growth trend derived from two data points

SA Power Networks' growth rate of 2.9 per cent per year is derived from only two data points (2001 and 2009). It does not include all 12 data points available for the entire 12 year period from 2000 to 2012.

To assess the impact of this omission, EMCa took historical demand data provided by ElectraNet without the adjustment SA Power Networks applied for the assumed consumer demand response and embedded generation. It then analysed the underlying growth based on that unadjusted data. Figure 2.8 shows EMCa's trend analysis. It includes a trend line for both SA Power Networks' data and EMCa's unadjusted historical data.

Figure 2.8 Trend analysis of SA Power Networks' underlying connection point peak demand



Sources: ElectraNet, *Summary CP historical and forecast peaks*, ENET0063, June 2012 [confidential]; ElectraNet, *Response to EMCa041 - Peak Load Data (Revised),* ENET244, 29 August 2012 [confidential]; ElectraNet, *Connection point peaks,* ENET221, 1 August 2012 [confidential]; ElectraNet, *Revenue proposal,* appendix J*;* EMCa analysis of data supplied by ElectraNet.

EMCa's analysis showed that the point-to-point growth rate for 2000–12 is 1 per cent. However, EMCa noted the trend line is heavily influenced by the 'above trend' demand in 2001 and the 'below trend' demand in 2012. To account for this effect, EMCa used a log-log function to determine the underlying growth rate for the 12 year period. The result was an average growth rate of 2.1 per cent.

The AER considers, and EMCa's advice supports the view, that this approach better indicates the underlying growth rate than do either the 12 year point-to-point growth rate or ElectraNet's peak-to-peak growth rate.[195]

Temperature uncertainty

Temperature is a key factor in driving peak demand. SA Power Networks' forecasting method is not based on a probabilistic planning model that explicitly accounts for temperature uncertainty. The AER considers that driving a five-year forecast from peak demands that occurred in just two half-hours, eight years apart, is not statistically valid. Such a method does not appropriately account for uncertainly in temperature related demand. EMCa's advice supports this view.[196]

The AER considers that good networking planning to meet peak demand requires explicit recognition of the effects of temperature uncertainty. Forecasting methods that use 10 per cent POE planning margins do this. Higher planning margins are costly and lead to investment in rarely used capacity.[197]

ElectraNet did not define its demand-related planning margin in POE terms. ElectraNet stated that its forecasts:[198]

> ...are not associated with a particular POE level. The forecasts are intended to represent peak demand levels that might be expected under extreme heatwave conditions that have tended to occur in South Australia once or twice a decade.

It stated it did not reconcile SA Power Networks' demand forecast to a 10 per cent POE because its obligations under the ETC require it to accept SA Power Networks' demand forecast 'as is'.[199] This issue is discussed in detail in section 2.5.

SA Power Networks' forecast presented as allowing for the possibility that heatwave conditions like those experienced in 2001 and 2009 will occur again in the 2013–18 regulatory control period.[200] However, SA Power Networks' forecasting method does not formally account for temperature related POE. It may appear that because its forecast is based on two temperature extremes that occurred in the space of a decade that SA Power Networks' demand forecast represents a 10 per cent POE (once in a decade) or even 20 per cent POE (twice in a decade). However, that is not the case. SA Power Networks' demand forecast is not based on actual temperature peaks. SA Power Networks made assumptions about what peak demand would have been had the temperature in 2001 reached the same temperature as it did in 2009. The 2001 temperature and the 2001 level of demand did not actually occur.

ElectraNet further stated:[201]

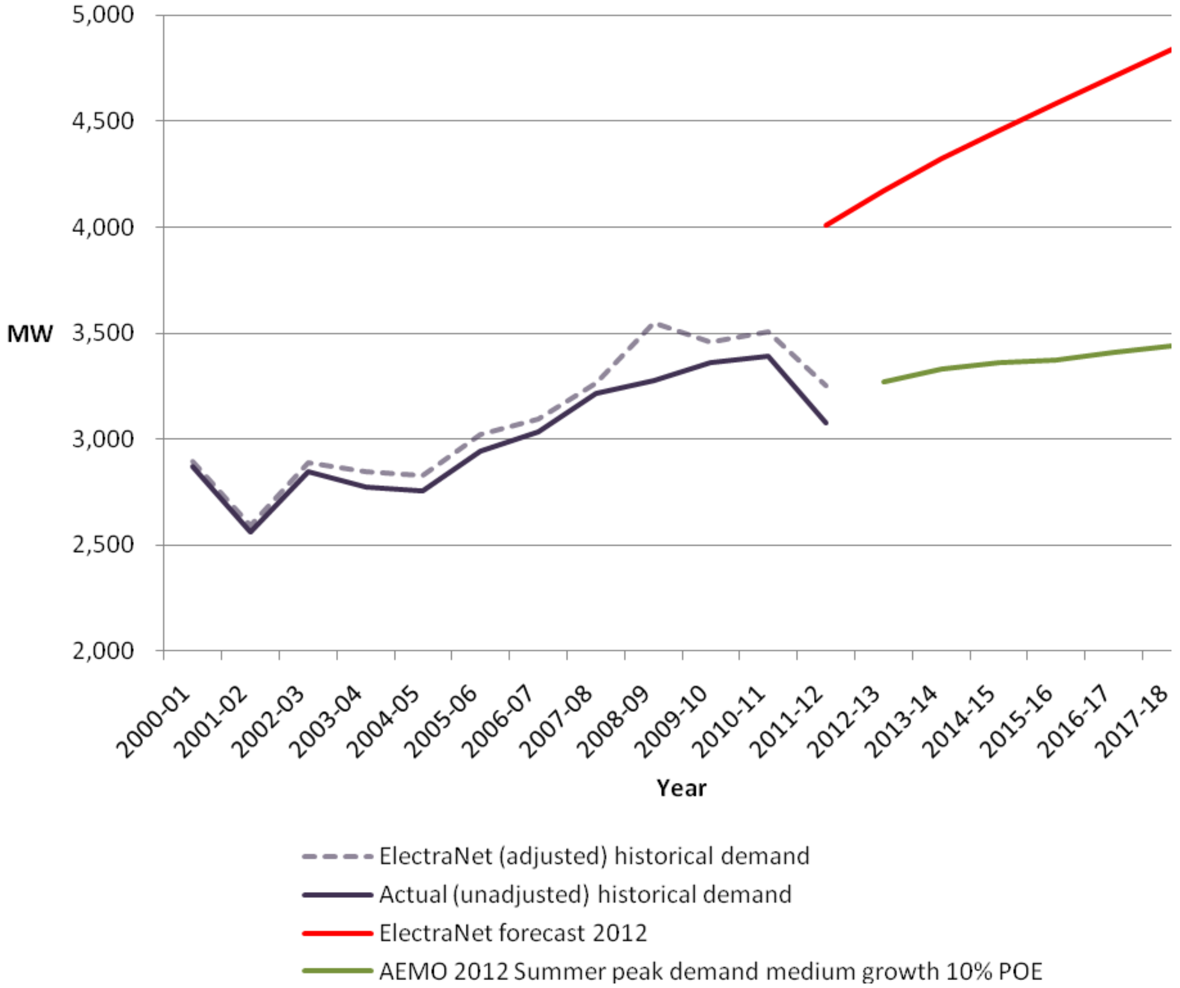
> The connection point forecasts are therefore compared with AEMO's 10% and 2% POE peak demand forecasts.

The AER is concerned that ElectraNet adopted a forecast that, while not based on a probabilistic planning model, sits within a 10 per cent and 2 per cent POE range. This is well in excess of the industry accepted standard of 10 per cent POE.

195 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, pp. 24–25.
196 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 15.
197 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 27.
198 ElectraNet, *Load forecast reconciliation*, ENET068, 7 June 2012, section 3.3.2 [public version].
199 ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, p. 4.
200 ElectraNet adjusted the 2001 heatwave peak upwards by 1.4 per cent. Accordingly, the 2001 peak is not a true representation of the heatwave conditions that actually occurred in 2001.
201 ElectraNet, *Load forecast reconciliation*, ENET068, 7 June 2012, p. 54 [public version].

EMCa compared ElectraNet's demand forecast with AEMO's 2012 10 per cent POE demand forecasts because these were derived from detailed temperature simulations and demand modelling of South Australian conditions. Figure 2.9 shows ElectraNet's proposed forecast compared with AEMO's 2012 summer peak demand at 10 per cent POE medium growth scenario. It shows that ElectraNet's demand forecast is significantly higher than AEMO's.

Figure 2.9 Comparison of historical (adjusted and unadjusted) demand and ElectraNet's proposed forecast and AEMO's 2012 summer peak demand at 10 per cent POE medium growth scenario



Sources: ElectraNet, *SA native demand and temperature annual max and average values*, ENET064, 4 June 2012; ElectraNet, *Connection point peaks,* ENET221, 1 August 2012 [confidential]; ElectraNet, *Revenue proposal,* appendix J; AEMO, *National electricity forecasting report,* 2012, pp. 6–10.

EMCa noted that AEMO's planning margin is around 5 per cent lower than the margin implicit in ElectraNet's 2013 peak demand forecast. [202]

EMCa also noted that, for South Australia, the margin between AEMO's 50 per cent POE and its 10 per cent POE is materially higher than the margin AEMO found for Queensland. While EMCa was not

[202] The planning margin or POE margin is the difference between the 50 per cent POE MW and the 10 per cent POE MW.

tasked to analyse this difference, it stated it considered the differences may be explained by South Australia's low load factor and more extreme temperature conditions.[203]

EMCa accounted for temperature uncertainty by developing its own linear trend forecast at 50 per cent POE for SA Power Networks' connection points using unadjusted historical demand data. This analysis is discussed further in section 2.6 where the AER's decision to substitute EMCa's alternative forecast is discussed in detail.

Photovoltaic generation

The AER considers that SA Power Networks did not properly account for the impact of photovoltaic generation that has occurred since 2009. EMCa's analysis supports this position. SA Power Networks projected its demand forecast from a peak that occurred in 2009, so it did not take into account the impact of the increase in photovoltaic generation since 2009.

AEMO's national electricity forecasting report showed South Australia has the highest penetration of photovoltaic generation of all the NEM states.[204] An increase in the use of photovoltaic generation means less electricity is being supplied from the grid.

The use of photovoltaic generation has been growing since about 2008. AEMO considered the uptake of photovoltaic generation has increased significantly only in the past two years, but will continue its recent trend and grow materially over the 2013–18 regulatory control period.

In its report on South Australian electricity, AEMO summarised penetration to date and forecast the annual impact that photovoltaic generation will have on peak demand through the 2013–18 regulatory control period.[205] AEMO estimated photovoltaic generation, at 2012, had reduced peak demand by around 100 MW from what it would have been. It forecast a peak reduction of 175 MW by 2017–18.[206]

The AER understands that AEMO is continuing to refine its assumptions and forecasting methods to account for the impact of photovoltaic generation on peak demand. That impact is not clear. Therefore, without further information, the AER considers AEMO's forecast is appropriate in the circumstances. The AER's adjustments for photovoltaic generation therefore reflect AEMO's forecast.

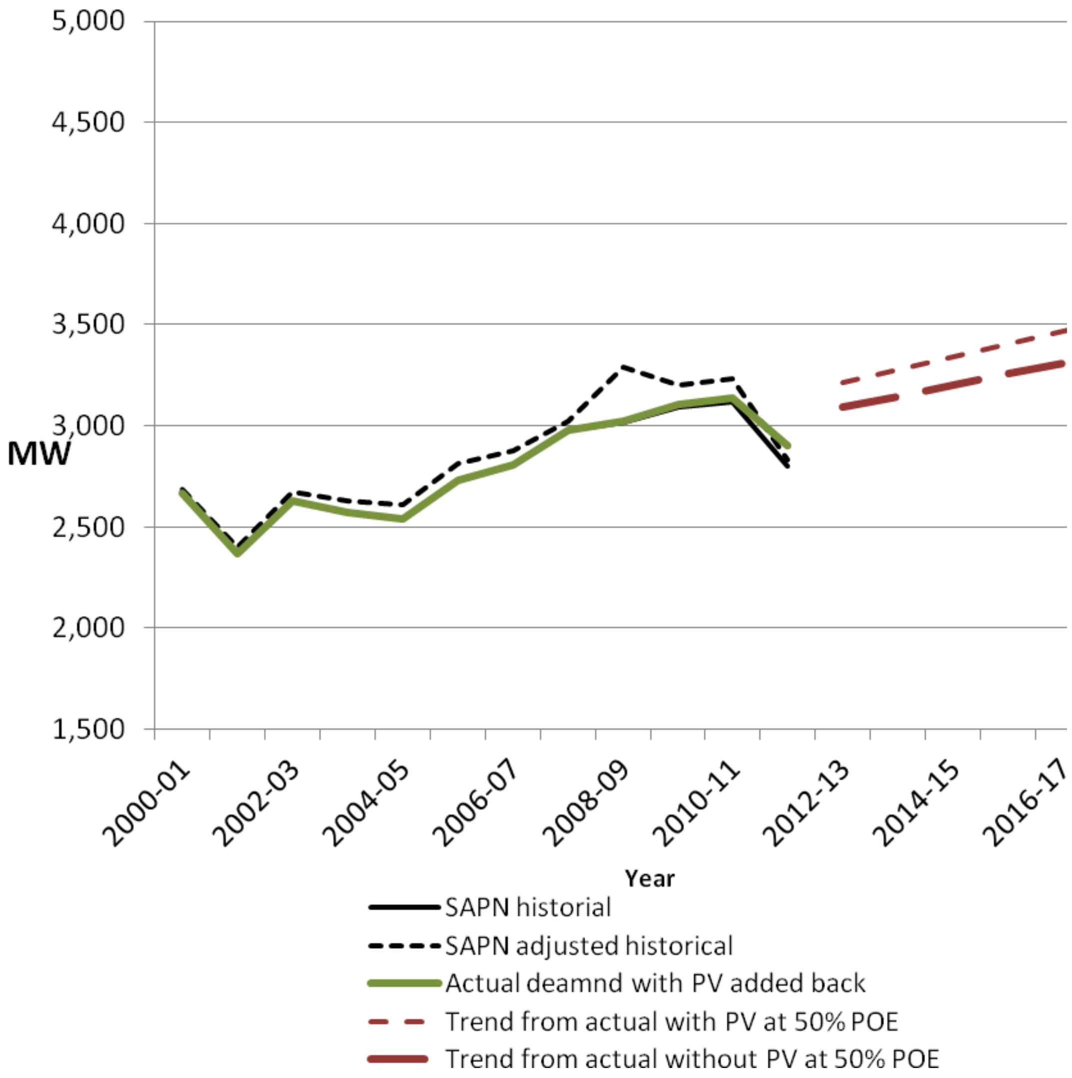
Because photovoltaic generation has had a relatively recent moderating effect on peak demand, it is also not accounted for in EMCa's 12 year historical linear trend. So, in order to assess the impact of photovoltaic generation on peak demand EMCa considered it separately and produced a linear trend that made explicit allowance for it. It did so by:

- adding back the effect of photovoltaic generation on historical demand to derive a proxy for underlying 'native' demand without photovoltaic generation
- determining a linear trend from this underlying native demand
- subtracting AEMO's forecast of the increasing contribution of photovoltaic generation to peak demand from the unadjusted trend line.

Figure 2.10 illustrates EMCa's analysis, which showed that adding back photovoltaic generation in the final years of the forecast makes a material difference to both the rate and level of demand growth.

[203] EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 27.
[204] AEMO, *National electricity forecasting report*, 2012, p. 3–1.
[205] AEMO, *South Australian electricity report*, 2012.
[206] AEMO, *South Australian electricity report*, 2012, p. 15.

Figure 2.10 Impact of photovoltaic generation on SA Power Networks' peak demand



Notes: The green line represents unadjusted historical data with estimated photovoltaic generation added back. The two trend lines show demand at 50 per cent POE with and without the effects of photovoltaic generation.

Source: EMCa analysis of data provided by ElectraNet and AEMO.

Diversity of peak demand

The AER does not accept ElectraNet's position that there is unity of peak demand (that is a diversity factor of 1.0) across all connection points and regions. EMCa's analysis of historical data showed that diversity across regions is present at peak times. This analysis was based on data relating to individual connection point demand and diversity factors associated with each connection point, at the time of system peak. It showed a system wide diversity factor (at the time of system peak) of 0.9.

The AER considers that a diversity factor should be applied to connection point forecasts when determining regional forecasts. While it seems logical that temperature driven peaks will have a high correlation in a given region, diversity data provided by ElectraNet for the time of system wide peaks did not show unity. For this reason, the AER considers that unity would be unlikely at the time of each region's peak and that a diversity factor should thus be applied. EMCa's advice supports this position.[207]

The AER also considers that diversity of peak demand exists at the regional level. EMCa analysed data on the date and time of the 2012 peak demand for each connection point. It then analysed this data by region. It found that typically only around half of the connection points peaked on the same day. In some cases, the non–coincident connection points peaked a day apart at a time when adjacent connection point loads would be expected to be high.[208] In other cases, non–coincident connection points peaked a month or more apart.[209]

EMCa's analysis included assessing load in the Adelaide metropolitan region (which comprises around 70 per cent of the South Australian load) at the time of state wide peak demand. It revealed a diversity factor of 0.955 for this region.[210] The AER considers it a reasonable assumption that the state wide peak occurred at the same time as the metropolitan 'regional' peak.[211] EMCa's analysis showed a much lower diversity factor in other regions (as low as 74 per cent) at the time of state wide peak. However, this data is a mix of inter-regional and intra-regional diversity and does not allow the AER to distinguish the different levels of diversity.

EMCa's analysis of historical data showed a system–wide diversity factor (at the time of system peak) of 0.9. EMCa's forecast includes an adjustment for diversity.

EMCa accounted for diversity by rounding up conservatively from the metropolitan area diversity factor derived from its assessment of ElectraNet's demand forecast. Thus, EMCa applies a diversity factor of 0.96. This means the forecasts used for regional planning should be around 4 per cent lower.

Reconciliation to a top down forecast

The AER considers a sound connection point forecast should be reconciled to a top down econometric forecast such as AEMO's state wide demand forecast.[212] ElectraNet has not done this.

SA Power Networks' connection point demand forecast is considerably higher than AEMO's 2012 state wide demand forecast. The AER considers that the omission of other factors produces an upward bias in SA Power Networks' demand forecast. Such factors include:

- gross state product (GSP) for the 2013–18 regulatory control period
- increasing prices for electricity
- the material impact of photovoltaic generation
- a growing presence of embedded generation in the network.

ElectraNet's connection point demand forecast growth rate of 2.9 per cent is materially above historical growth rates of 1.7 per cent.[213] In August 2012, AEMO published its national electricity

207 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, section 5.4.6, pp. 28–29.
208 The non coincident connection points are those connection points where peak demand did not occur at the same time.
209 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 26.
210 SA Water was excluded because it has an extremely low load factor.
211 This assumption is based on the Adelaide metropolitan region comprising a substantial proportion of South Australian load. The AER also considers the pattern of use across the connection points was likely similar at the time of regional peak.
212 AEMO, *National electricity forecasting report*, 2012, p. 6–10.
213 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, pp. 22 and 30.

forecast.[214] AEMO's forecast for South Australia for summer 2012–13 is 3271 MW[215] compared with ElectraNet's forecast of 4167 MW.[216]

AEMO revised its 2012 forecasts[217] down from its 2011 forecasts.[218] EMCa advised the AER that it agreed with AEMO's assessment of the economic outlook for South Australia. It also agreed with AEMO's reduced average growth rate in the forecast which is now 1 per cent per year (down from the 2011 forecast of 1.7 per cent). AEMO's 2012 forecasts were influenced by lower forecasts of gross state product, reduced manufacturing consumption, the inclusion of the impact of photovoltaic generation, and the delay of major load connections.[219]

Forecast comparison

Table 2.2 shows AEMO's top down forecast and ElectraNet's connection point forecast for the 2013–18 regulatory control period. AEMO records and forecasts state wide generation, so its forecasts represent diversified demand and account for transmission losses and generator own use. By contrast, ElectraNet relied on SA Power Networks' connection point demand forecasts which are undiversified. So, while Table 2.2 and Figure 2.11 show AEMO's 2012 forecast and ElectraNet's forecast, they are not a direct comparison.

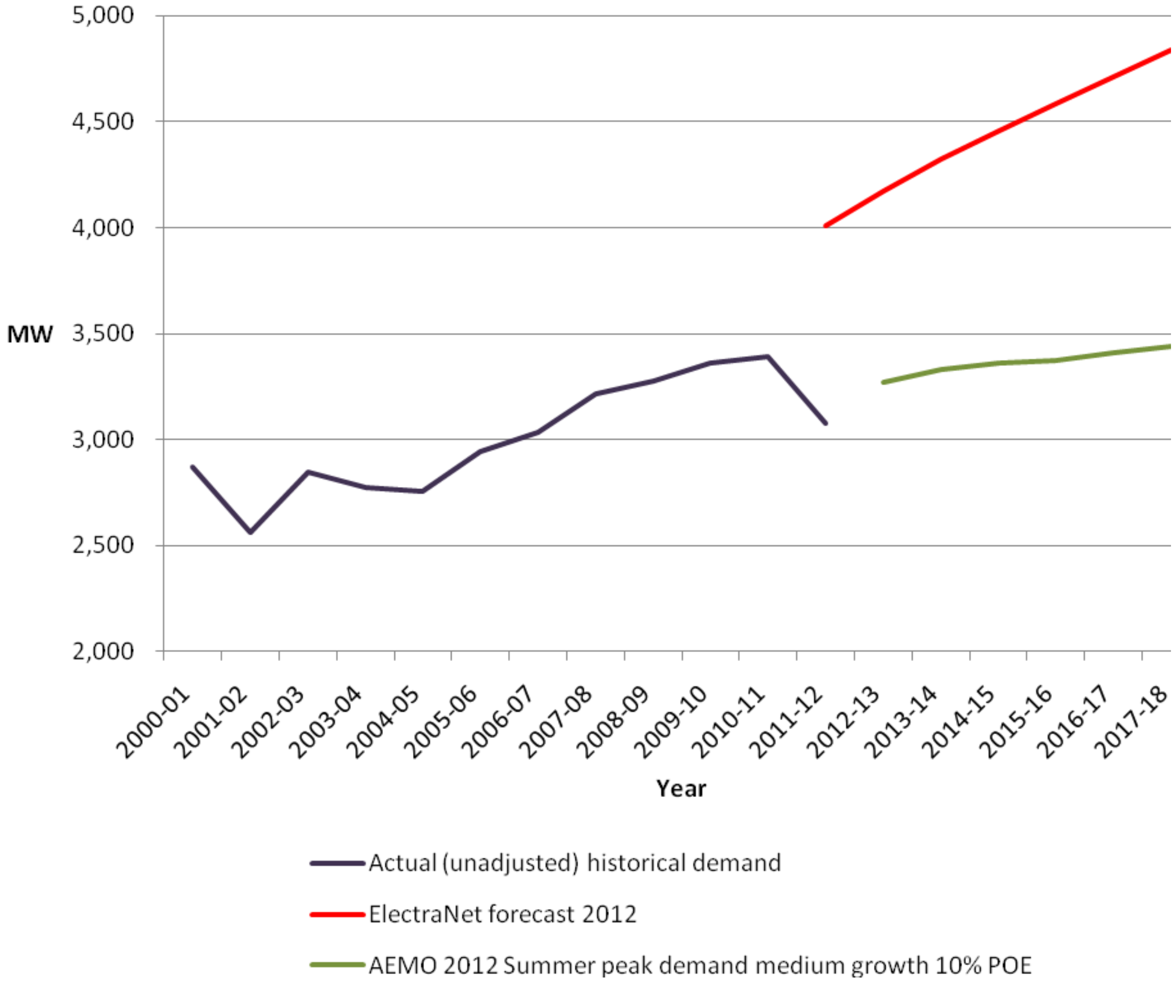
Table 2.2 Comparison of peak demand forecasts for South Australia

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
AEMO state wide 2012, POE 10% diversified	3271	3332	3362	3375	3407	3439
ElectraNet 2012, heatwave conditions, undiversified	3932	4077	4200	4321	4443	4553

Source: ElectraNet, *Revenue proposal,* appendix J; AEMO, *National electricity report for South Australia*, 2012.

214 AEMO, *National electricity forecasting report*, 2012.
215 AEMO, *National electricity forecasting report*, 2012, p. 6–10.
216 ElectraNet, *Revenue proposal,* appendix J.
217 AEMO, *National electricity forecasting report*, 2012.
218 AEMO, *SA Supply and demand outlook*, 2011
219 AEMO, *National electricity forecasting report*, 2012, p. 6–1.

Figure 2.11 AEMO's 2012 forecast compared with ElectraNet's forecast



Source: ElectraNet, *revenue proposal,* appendix J; AEMO, *National Electricity Report for South Australia*, 2012.

ElectraNet expressed concern that AEMO's 2011 forecast was biased.[220] ElectraNet considered that AEMO's 2011 forecast needed to be adjusted for omissions regarding demand side participation and load shedding and different assumptions regarding photovoltaic generation and spot loads. AEMO stated it modified its forecasting method to improve the quality and consistency of its forecasts,[221] but the AER understands some areas of divergence may still exist between ElectraNet and AEMO despite these changes.[222]

2.4.2 ElectraNet's past demand forecasting performance

This section compares actual demand with ElectraNet's previous demand forecasts.

The Energy Users Association of Australia (EUAA) submitted that ElectraNet has consistently and systematically over-forecast its peak demand and notes that ElectraNet proposed an annual growth rate in maximum demand of around 2.7 per cent across the 2013–18 regulatory control period.[223] The

220 ElectraNet, *Load forecast reconciliation,* ENET068, 7 June 2012, p. 54.
221 AEMO, *National electricity forecasting report*, 2012, p. 1–1.
222 AEMO, *Demand forecasting presentation to AER*, September 2012.
223 EUAA, *Submission on ElectraNet's revenue proposal for 2013/14-2017/18*, August 2012, p. 7.

EUAA stated that there is a strong incentive for TNSPs to overstate their forecasts as they stand to benefit from the resulting increase in capex and eventually their asset base.

The EUAA stated AEMO revised down its 2012 demand forecasts for South Australia and that its 2012 medium growth forecast at 10 per cent POE is estimated to rise from 3332 MW to 3439 MW between 2013 and 2018. The EUAA stated this represents a compound average growth rate of only 0.70 per cent per year. This is around half that proposed by ElectraNet. The EUAA submitted that actual growth in peak demand is more likely to sit between the medium growth and the low growth rate estimated by AEMO in 2012.

The AER is concerned that ElectraNet's recent history may suggest it has over forecast demand. The discussion in previous sections suggests that ElectraNet's methods and processes may introduce an upward bias to its demand forecasts, including the forecast for the 2013–18 regulatory control period.

Capex forecasts are developed to meet a particular demand forecast. An excessive demand forecast also suggests an excessive capex forecast. An excessive capex forecast is not consistent with the national electricity objective (NEO) and implies customers may pay more for a secure reliable supply of electricity than is otherwise necessary.[224]

Figure 2.12 compares ElectraNet's forecasts for each of the last three revenue proposals with actual demand between 2003 and 2012. Actual demand has been below ElectraNet's forecasts for each year of the relevant regulatory control period, except 2009. The AER has not undertaken an ex-post review of ElectraNet's previous demand forecasts to form an opinion about its past performance. Nevertheless, the AER notes that ElectraNet did not account for the decline in demand since 2009 in its revenue proposal demand forecast. The AER considers that the inclusion of a robust ex-post review would provide assurance about the reliability of a TNSP's demand forecast that underpins its network augmentation capex forecast.

[224] NEL, part 1, section 7.

Figure 2.12 ElectraNet's demand forecasts for previous revenue proposals

Source: ElectraNet, Revenue proposals for 2003, 2008 and 2013.

2.5 The South Australian Electricity Transmission Code

ElectraNet submitted that it must accept SA Power Networks' demand forecast 'as is' because it is obliged to do so under the ETC.[225] The AER must consider whether, despite finding that ElectraNet's demand forecast is not sound and therefore is not a realistic expectation of demand, it is required to accept ElectraNet's demand forecast.

2.5.1 AER's decision

For the reasons set out below, the AER considers:

- ElectraNet does not have a regulatory obligation under the ETC to accept SA Power Networks' demand forecasts 'as is'
- the AER may use a substitute forecast of required capex because it is not satisfied that ElectraNet's total forecast capex for the regulatory control period reasonably reflects the capex criteria.[226]

[225] ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, p. 4
[226] NER, clause 6A.6.7(c)(3).

2.5.2 AER's assessment

This section:

- discusses the background to the introduction of ETC TC/07
- identifies ElectraNet's obligations under the NER
- discusses the relevant obligation under the ETC.

Table 2.3 sets out definitions and concepts discussed in this section.

Table 2.3 Relevant definitions and concepts

Concept	Definition
AMD	Agreed maximum demand means the demand specified as such in the connection agreement between ElectraNet' and SA Power Networks.[227] Clause 1.1 of the connection agreement defines AMD to mean ...in respect of an Exit Point ... the average demand or load (in KW or MW) for a trading interval which occurs during a maximum demand period, nominated by [SA Power Networks] and specified in Schedule 3, as varied from time to time in accordance with clause 13.4.[228]
FAMD	Forecast agreed maximum demand means the agreed maximum demand forecast for a given year that is agreed with the customer 3 years prior to when the agreed maximum demand is contracted.[229]
Contracted AMD	Contracted AMD is AMD that is specified in Schedule 2 of the Transmission connection agreement between ElectraNet and SA Power Networks as varied from time to time in accordance with the terms of the connection agreement.
ETC standards	The reliability standards under the ETC require ElectraNet to supply the equivalent line capacity or transformer capacity for at least 100 per cent of contracted AMD. In general, ElectraNet must not contract for an amount of agreed maximum demand which is greater than 100 per cent of the installed transmission line and transformer capacity.[230]

ESCOSA's review of the ETC

Currently, AMD is contracted on a 12-month forecast. The current ETC (TC/06) provides that ElectraNet must use its best endeavours to remedy a breach of the ETC standards within 12 months and at the latest within three years.[231]

The ETC was reviewed by ESCOSA in 2010. Following the review, ESCOSA made changes to the provisions of the ETC.[232] ESCOSA's changes reflected the concern that as AMD was contracted on a 12 month forecast, there was limited opportunity for planning.[233] To address this concern, clause 2.11

227 ElectraNet and SA Power Networks, *Transmission Connection Agreement*, 22 November 1999 [confidential].
228 ElectraNet and SA Power Networks, *Transmission Connection Agreement*, 22 November 1999 [confidential], clause 1.1, p. 2.
229 ETC, TC/07, clause 10.1.
230 ETC, TC/07, clause 2.12.
231 ETC, TC/06, clause 2.10.3.
232 ESCOSA, *Review of the Electricity Transmission Code, Final Decision*, February 2012.
233 ElectraNet, *Transmission Connection Agreement*, 22 November 1999, clause 7.7, p. 18.

was developed. The clause introduces the concept of FAMD.[234] The new provisions of the ETC will come into effect on 1 July 2013.[235]

The new clause 2.11 of the ETC provides that:

> ... if a change in FAMD at an exit point or group of exit points will result in a future breach of a standard ... a transmission entity must ensure that the equivalent capacity at the exit point or group of exit points is sufficient to meet the required standard within 12 months of the identified future breach date.

ElectraNet stated that as a result of these changes to the ETC it must accept SA Power Networks' demand forecasts 'as is'.[236] The AER considers this position is not correct. The AER's reasoning for this conclusion is outlined in section 2.5.

Obligations under the NER

The AER must accept ElectraNet's forecast of required capex if the AER is satisfied that the total of the forecast capex for the regulatory control period reasonably reflects each of the capex criteria.[237] If the AER is not satisfied that ElectraNet's total forecast capex for the 2013–18 regulatory control period reasonably reflects the capex criteria then it must not accept ElectraNet's capex forecast.[238] If the AER does not accept ElectraNet's capex forecast, the AER must use a substitute forecast of required capex expenditure.[239] The capex criteria are:

1. the efficient costs of achieving the capex objectives;
2. the costs that a prudent operator in ElectraNet's circumstances would require to achieve the capex objectives; and
3. a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

Under the NER, ElectraNet's revenue proposal must include the total forecast capex for the relevant regulatory control period which ElectraNet considers is required in order to achieve the capex objectives.[240] Relevantly, the capex objectives include the total forecast capex required to:

- meet the expected demand for prescribed transmission services over that period;
- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

ElectraNet submitted that under the ETC, which is an applicable regulatory obligation, it must accept SA Power Networks' demand forecasts and build its network to meet those forecasts.[241] Accordingly, SA Power Networks' forecasts form the basis of ElectraNet's revenue proposal.

[234] ETC, TC/07, clause 2.11, effective 1 July 2013.
[235] ETC TC/07, effective 1 July 2013. The AER considers that the provisions of ETC TC/07 are the applicable provisions for the purposes of the ElectraNet 2013-18 distribution determination. Under clauses 6A.6.7 (a) of the NER, ElectraNet's Revenue proposal, must include the total forecast capex for the relevant regulatory control period, that ElectraNet considers is required to achieve the capex objectives. The relevant regulatory control period is the 2013–18 regulatory control period which commences on 1 July 2013. Therefore, given that TC/07 also commences on 1 July 2013, these provisions are the applicable ETC provisions for the relevant regulatory control period.
[236] ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, p. 4.
[237] NER, clause 6A.6.7(c)(3).
[238] NER, clause 6A.6.7(d).
[239] NER, clause 6A.6.7(f).
[240] NER, clause 6A.6.7(a).
[241] ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, p. 4.

A regulatory obligation or requirement is an obligation or requirement under an Act of a participating jurisdiction or any instrument made or issued under that Act. The definition of 'participating jurisdiction' in section 5 of the NEL includes the state of South Australia. The ETC is made by the ESCOSA under section 28 of the *Essential Services Act* 2002 (SA).

Therefore, the AER accepts that the ETC satisfies the definition of 'regulatory obligation or requirement' under the NEL and NER. However, for the reasons discussed below, the AER does not accept ElectraNet's submission that it has a regulatory obligation to accept SA Power Networks' demand forecasts 'as is'.

Relevant obligations under the ETC

The relevant obligation under the ETC is for ElectraNet to react to a change in FAMD. The obligation does not require ElectraNet to accept SA Power Networks' demand forecast 'as is'. The AER considers that ElectraNet should review the demand forecast proposed by SA Power Networks and then negotiate the level of FAMD it considers is appropriate.

Under the ETC, ElectraNet and SA Power Networks need to **agree** to a level of demand 3 years in advance of when they anticipate they will need to meet that level of demand. FAMD is the level of demand both ElectraNet and SA Power Networks anticipate will become contracted AMD three years from the time the FAMD is agreed.[242] FAMD does not automatically become contracted AMD. AMD is defined in the ETC as the demand specified as such in the connection agreement between ElectraNet and SA Power Networks. Variations to contracted AMD are governed by the transmission connection agreement.

In its revenue proposal, ElectraNet appears to equate SA Power Networks' demand forecast to FAMD. However, FAMD does not come into effect until the amended ETC commences on 1 July 2013. Further, FAMD is, by definition, a **single year** of anticipated demand forecast 3 years in advance.

ElectraNet's obligations in relation to FAMD under the amended ETC (TC/07) are:

- to agree FAMD with SA Power Networks.
- where there is a **change** in FAMD, to ensure that the equivalent capacity at the exit point or group of exit points is sufficient to meet the required reliability standard within 12 months of the identified future breach date.[243]
- to use its best endeavours to acquire all necessary land and easements on the basis of FAMD, prior to a change in FAMD causing a breach of the reliability standards referred to in the ETC.[244]

The obligation is to react to a change in FAMD

The obligation to react to a change in FAMD under the ETC is to allow ElectraNet sufficient time to plan any changes to its network. The AER understands that ESCOSA's objective in changing the

242 NEL, section 2D(1)(b); NER, clause 6A.6.7(a)(2).
243 ETC, TC/07, clause 2.11.1.
244 ETC, TC/07, clause 6.3.1; The AER notes that unless FAMD becomes contracted AMD the ETC standards will not be breached. Variations to AMD are governed by clause 13.4 of the transmission connection agreement between ElectraNet and SA Power Networks.

provisions of the ETC to include the concept of FAMD was to provide ElectraNet a planning window of four years to remedy a potential breach of the standard.[245]

The obligation is in addition to obligations under the NER

The ETC states that any obligations imposed under the ETC are in addition to those imposed under the NER.[246] If anything in the ETC is inconsistent with the NER, the provisions of the NER have priority to the extent of the inconsistency.[247] However, the exception is where the ETC imposes an obligation that is higher or more onerous than any corresponding obligation contained in the NER.

Under the NER, ElectraNet's total forecast capex must be based on a realistic expectation of demand for the regulatory control period. Under the ETC, ElectraNet is required to take steps when a change in FAMD will result in a future breach of a reliability standard under the ETC.[248] If such a change in FAMD occurs, ElectraNet must ensure that the equivalent capacity at the exit point or group of exit points is sufficient to meet the required standard within 12 months of the identified future breach date.

The relevant standard under the ETC is contracted AMD

The required standard is set by reference to **contracted** AMD.[249] It is not set by reference to FAMD. That is, FAMD is not the basis for the ETC reliability standard. Rather, it is a change in FAMD that will trigger ElectraNet's obligation to ensure it has sufficient capacity to meet the reliability standard for the contracted AMD.

While the AER acknowledges that ElectraNet's obligations under the NER and ETC are related, as they both require demand to be forecast, the AER considers they are separate but complementary obligations. Under the NER, ElectraNet is required to provide a realistic expectation of demand over the regulatory control period. Under the ETC, ElectraNet is required to react to a change in FAMD.

No obligation under the ETC to develop a demand forecast

There is nothing in the ETC that requires ElectraNet to develop a demand forecast. However, implicit in the obligation to react to a change in FAMD is the need to agree a demand forecast. In order to determine whether it will need to take steps to react to a change in FAMD, ElectraNet will necessarily need to review the demand forecast proposed by SA Power Networks.

Such a review will assist ElectraNet to:

- negotiate agreements for FAMD with SA Power Networks
- ascertain whether a change in FAMD is such that ElectraNet will be required to augment its network to the extent that, if the negotiated FAMD were to become contracted AMD, it would not be able to meet the reliability standards in the ETC for that level of demand.

Negotiating FAMD

ElectraNet has not negotiated FAMD with SA Power Networks. EMCa considered that the wording of the ETC refers to 'agreed' forecasts and that it had not been presented with evidence of an agreement process between ElectraNet and SA Power Networks. EMCa did not have any evidence of

245 ESCOSA, *Review of the electricity transmission code*, final decision, February 2012, pp. 28–32.
246 ETC, TC/06 and ETC TC/07, clause 1.6.1.
247 ETC, TC/07, clause 1.6.2.
248 ETC, TC/07, clause 2.11.1.
249 Emphasis added.

ElectraNet's analysis of SA Power Networks' forecast and it understood that ElectraNet did not seek any modifications to those forecasts.[250]

The AER considers that once ElectraNet agrees an FAMD with SA Power Networks, the agreed amount becomes FAMD for the purposes of the ETC. However, the AER also considers that there is room for ElectraNet to negotiate the FAMD prior to it being agreed. ElectraNet stated it was concerned about having to accept uncontracted increases in FAMD.[251] During ESCOSA's review of the ETC, ElectraNet made a submission on the issue. In May 2011, ElectraNet stated:[252]

> That the forecast agreed maximum demands are uncontracted, with no recourse against customers for the accuracy of their forecasts, leads to a risk of significant advancement of transmission developments and augmentations to meet uncommitted forecast increases in demands.
>
> Customers could make strategic use of uncommitted increases in forecast agreed maximum demand to ensure a level of transfer capability is available on the off chance of a project going ahead. This could lead to the advancement of transmission developments and augmentations to meet the forecast increases in demand. These augmentations may provide additional levels of reliability over and above those required by the Code or negotiated under the applicable Transmission Connection Agreement. If the forecast demands do not materialise, customers at large will pay for the augmentations.

To overcome this concern, ElectraNet proposed that the definition of FAMD be amended to include the phrase 'agreed with' the customer. ElectraNet stated:[253]

> We believe the definition of forecast agreed maximum demand should therefore relate to either the agreed medium peak demand forecast provided by ETSA Utilities, or a forecast agreed between the parties in the case of direct connect customers, rather than simply a set of numbers provided by the customer.

The new provisions of the ETC contain the changes proposed by ElectraNet. In its final decision, ESCOSA stated:

> In regard to forecast AMD, ElectraNet proposed that the demand forecast should be agreed with the customer rather than provided by the customer. The Commission notes that this would provide a platform for negotiation which would establish the basis on which the agreed maximum demand forecast is based; whether the ETSA Utilities' medium growth forecast (summer peak demand forecasts) or medium peak demand forecast, as proposed by ElectraNet, are used.

ElectraNet's submission and ESCOSA's final decision support the view that ElectraNet may have input into FAMD prior to it being agreed. This diminishes ElectraNet's position that it must passively accept SA Power Networks' demand forecast.

Conclusion

The AER considers that ElectraNet's obligation under the ETC is to react to a change in FAMD. This obligation is not an obligation to accept FAMD as presented to it by SA Power Networks 'as is'. The AER considers that there is no conflict between ElectraNet's obligation to react to a change to FAMD and the obligation under the NER to provide a total forecast capex based on a realistic expectation of demand.

To the extent that the obligation to react to a change in FAMD requires ElectraNet to review SA Power Networks' demand forecast, that obligation is not inconsistent with its obligation to develop a demand forecast under the NER. The obligations complement each other, but each obligation serves a different purpose. One is for planning to avoid anticipated breaches of the ETC reliability standards.

[250] EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 13.
[251] ElectraNet, *Submission to the Review of the Electricity Transmission Code*, May 2011, p. 3.
[252] ElectraNet, *Submission to the Review of the Electricity Transmission Code*, May 2011, pp. 3 and 4.
[253] ElectraNet, *Submission to the Review of the Electricity Transmission Code*, May 2011, p. 4.

The other serves to drive a total forecast capex for the purposes of a revenue determination under the NER.

Accordingly, the AER does not accept that the FAMD agreed between ElectraNet and SA Power Networks is an applicable regulatory obligation for the purpose of determining the forecast of total capex required for the 2013–18 regulatory control period.

2.6 Substitute demand forecast

Section 2.4 sets out the AER's concerns around ElectraNet's proposed demand forecast. The AER is not satisfied that ElectraNet's demand forecast is a realistic expectation of demand.[254] In accordance with the NER, the AER must develop a substitute demand forecast.[255] The AER's decision is to substitute the forecast developed by EMCa as part of its assessment of ElectraNet's forecast.

The AER understands that ElectraNet recognises the circumstances requiring a lower demand forecast and is therefore engaging with ESCOSA with a view to confirming its understanding of its obligations under the ETC.[256]

The AER considered adopting AEMO's 2012 forecast. However, the report from AEMO, reconciling its demand forecast with ElectraNet's was not available in time for this draft decision. The South Australian Government submitted to the AER that:[257]

> It is important to reconcile the state-wide demand forecast with the connection point forecasts developed by SA Power Networks (and the direct connect customers) to ensure that network planning is done on a consistent basis with expected state-wide peak demand levels. The AER and AEMO must undertake this reconciliation to provide further confidence in the connection point forecasts used by ElectraNet, so as to substantiate the correlation between AEMO's top down econometric forecasts and ElectraNet's bottom up connection point forecasts.
>
> Confirmation of the reconciliation of ElectraNet's connection point demand forecasts will ensure that the forecasts are reasonable, therefore providing an appropriate basis to determine, with confidence, the forward capital expenditure requirements.

The AER understands that AEMO is working with ElectraNet to refine the inputs and assumptions AEMO makes in forecasting demand for South Australia and to reconcile its forecast with ElectraNet's. The AER did not ask EMCa to independently review AEMO's 2012 demand forecast for South Australia, preferring to rely on the expertise of AEMO, the national transmission planner.

EMCa noted that AEMO's 2012 national electricity forecasts present a modified and updated approach to forecasting demand in all of the NEM states.[258] In the absence of a reconciliation report from either ElectraNet or AEMO, the AER's decision is to substitute the linear trend forecast produced by EMCa as part of its assessment of ElectraNet's forecast.

In summary EMCa has:[259]

- determined a linear trend forecast at 50 per cent POE for SA Power Networks' connection points using unadjusted historical demand data to account for temperature uncertainty

254 NER, clause 6A.6.7(c)(3).
255 NER, clauses 6A.6.7(d) and 6A.12.1(c).
256 ElectraNet, discussion with AER on 3 October 2012.
257 South Australian Government, *Submission to AER*, 27 September 2012, p. 2.
258 EMCa, *Review of demand forecast proposed by ElectraNet,* October 2012, p. 21; AEMO, *National electricity forecasting report*, 2012.
259 NER, clauses 6A.6.7(d) and 6A.14.1(2)(ii).

- made a separate adjustment for photovoltaic generation based on AEMO's recent forecasts for this factor
- adjusted the data to create a temperature related POE to facilitate capex planning with sufficient temperature related demand margin
- added ElectraNet's direct customer forecasts
- adjusted the data for regional diversity.

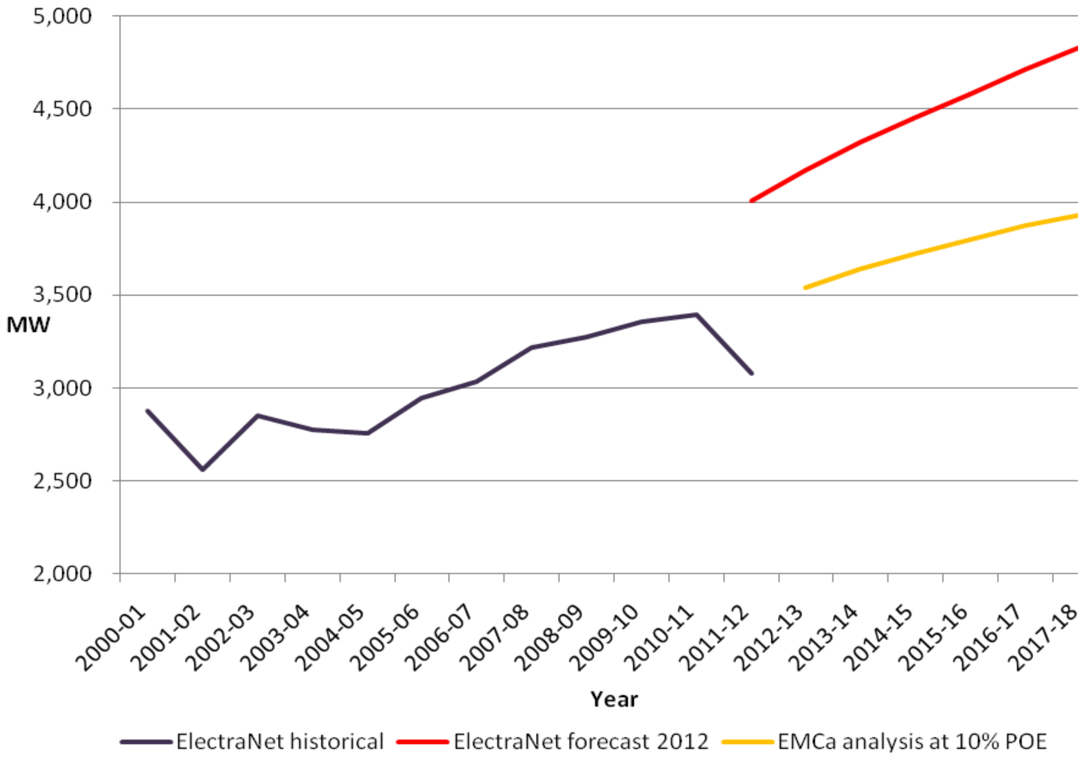
As EMCa considered that ElectraNet's forecast did not properly account for temperature uncertainty, EMCa developed a linear trend forecast at 50 per cent POE for SA Power Networks' connection points using unadjusted historical demand data.[260] EMCa assessed the difference between SA Power Networks' connection point data for 2013 and EMCa's 50 per cent POE trend line. It used 2013 as the base year for determining the margin for all years, given that any differences in growth rate between the data sets will have little impact in the starting year. It did not include ElectraNet's direct connect customers because their peak demand requirements have little to do with fluctuations in temperature.

EMCa then separately accounted for the impact of photovoltaic generation and regional diversity as described in section 2.4.1. EMCa then included ElectraNet's direct connect customer demand forecasts.

Figure 2.13 shows a comparison of ElectraNet's forecast with EMCa's linear trend forecast. EMCa's analysis showed that SA Power Networks' connection point forecast is 14 per cent higher than the forecast developed by EMCa.

[260] Fifty per cent POE means there is an equal probability of actual demand being more or less that the trend line.

Figure 2.13 Comparison of ElectraNet's forecast with EMCa's forecast



Notes: The yellow line is derived by adding AEMO's 10 per cent POE demand margin to EMCa's 50 per cent POE trend forecast which is in turn derived from SA Power Networks' connection point. The red line is ElectraNet's forecast including its direct connect customers. The historical data is unadjusted.

Source: EMCa analysis of data supplied by ElectraNet.

Comparison of ElectraNet's, EMCa's and AEMO's 2012 demand forecast

EMCa also adjusted AEMO's 2012 demand forecast for South Australia so it could be compared with EMCa's forecast. The adjustments were based on the 2011 adjustments made by ElectraNet in its reconciliation report.[261] In essence, the adjustments made were to place all forecasts onto a common basis. Specifically, each forecast was adjusted to a regionally-diversified connection point demand forecast, at a POE level suitable for planning purposes. These types of forecasts are used for regional augmentation planning purposes.

Specifically, EMCa adjusted the data in AEMO's 2012 forecast to:

- un-diversify the load to an equivalent 'undiversified connection point sum'
- deduct transmission losses
- make an aggregate adjustment for the factors identified by ElectraNet, including adjusting for:[262]
  - offset and spot load differences
  - claimed AEMO model bias regarding controlled loads and solar photovoltaic generation[263]

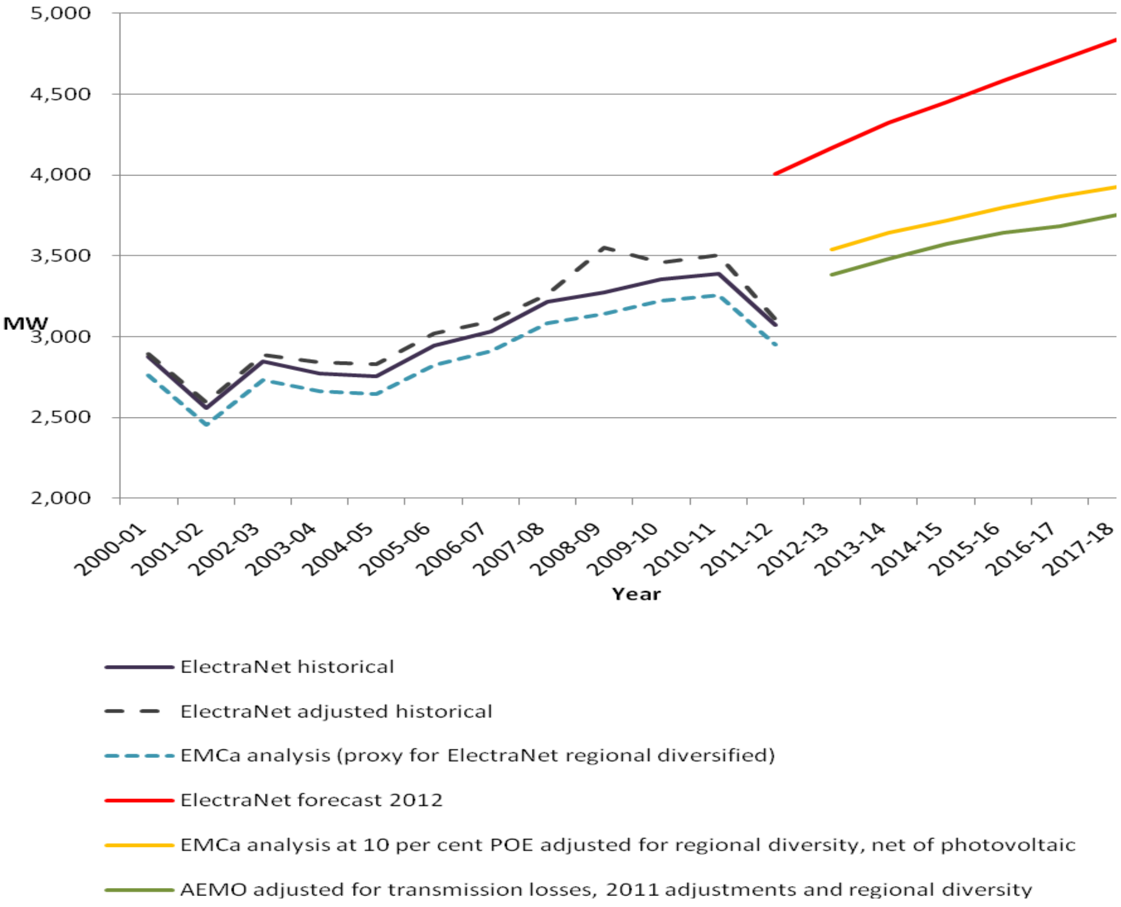
261 ElectraNet, *Load forecast reconciliation,* ENET068, 7 June 2012 [public version].
262 ElectraNet, *Load forecast reconciliation report,* ENET068, 7 June 2012, pp. 40 [public version].

- the omission of demand side participation.

- diversify back to the regional level.

Figure 2.14 shows ElectraNet's forecast compared with EMCa’s trend projection and EMCa's adjusted AEMO projection. The historical data in this chart has been adjusted by EMCa to place it on a common footing equivalent to a 'regional diversified actual demand'.

Figure 2.14 Comparative analysis of peak demand forecasts for regional augmentation capex planning



Source: EMCa analysis of data provided by ElectraNet.

The trend projection developed by EMCa is 624 MW (14 per cent) below ElectraNet’s regional augmentation forecast in 2017–18. Based on this analysis, EMCa's demand level in 2017–18 is only just at the level that ElectraNet forecast for 2012–13. EMCa's adjustments to AEMO's 2012 demand forecast show that AEMO's adjusted forecast is approximately 800 MW (17 per cent) below ElectraNet’s demand forecast in 2017–18.

[263] EMCa did not provide an opinion on whether the claims made by ElectraNet regarding AEMO's alleged model bias were reasonable as this was beyond its terms of reference. The AER has not formed an opinion on the validity of ElectraNet's claimed bias. The AER is aware that both ElectraNet and AEMO are continuing to refine their forecasting methods to take into account a variety of views regarding assumptions and forecasting methods relevant to producing a connection point demand forecast.

EMCa's trend projection sits between ElectraNet's forecast and AEMO's (adjusted) forecast. The AER considers that EMCa's trend projection, while not based on a full econometric or other quantitative analysis, is closer to AEMO's 2012 forecast than to ElectraNet's.[264]

ElectraNet's connection point forecast is materially higher than AEMO's 2012 state wide 10 per cent POE medium demand forecast. EMCa noted that AEMO's forecast can be reasonably expected to be lower than ElectraNet's. An econometric model, such as AEMO's accounts for price rises and the slowing of economic growth. As such, a lower forecast may be expected notwithstanding the presence of significant mining opportunities (which the model accounts for separately).

The AER considers that EMCa's trend projection forecast is a reasonable basis to develop an alternative network augmentation capex proposal consistent with a realistic expectation of demand. The impact of the AER's substitute demand forecast on capex is set out in attachment 4.

2.7 Revisions

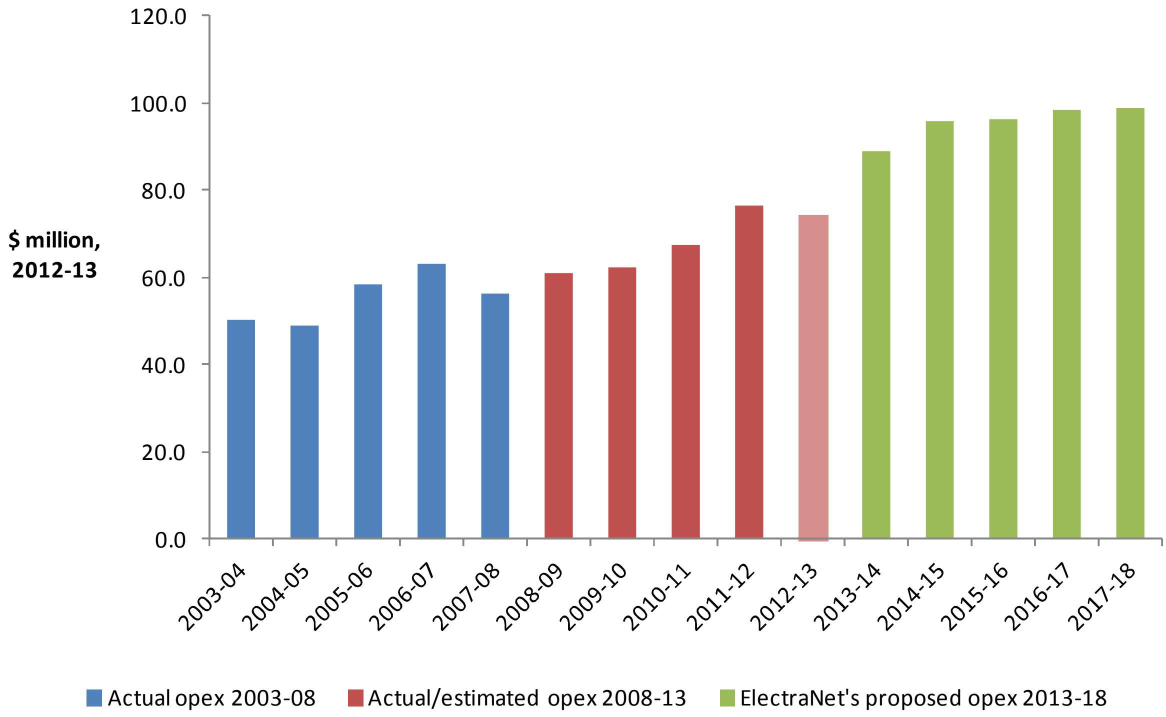
Revision 2.1: section 2.1 sets out the AER's substitute demand forecast for the 2013–18 regulatory control period.

264 EMCa, *Review of demand forecast proposed by ElectraNet*, October 2012, p. 30.

3 Forecast expenditure

ElectraNet has proposed significant increases in its operating expenditure (opex) and replacement / refurbishment capital expenditure (capex) for the 2013–18 regulatory control period. In light of these proposed increases the AER has closely considered the key drivers for the increases. Figure 3.1 shows ElectraNet's past and proposed opex. ElectraNet has proposed a 40 per cent real increase in its opex.[265] Figure 3.2 shows ElectraNet's past and forecast replacement / refurbishment capex. ElectraNet has proposed a 68 per cent real increase in its replacement capex. ElectraNet's refurbishment capex is an additional $54 million ($2012–13).

Figure 3.1 ElectraNet's actual and proposed total opex ($ million, 2012–13)



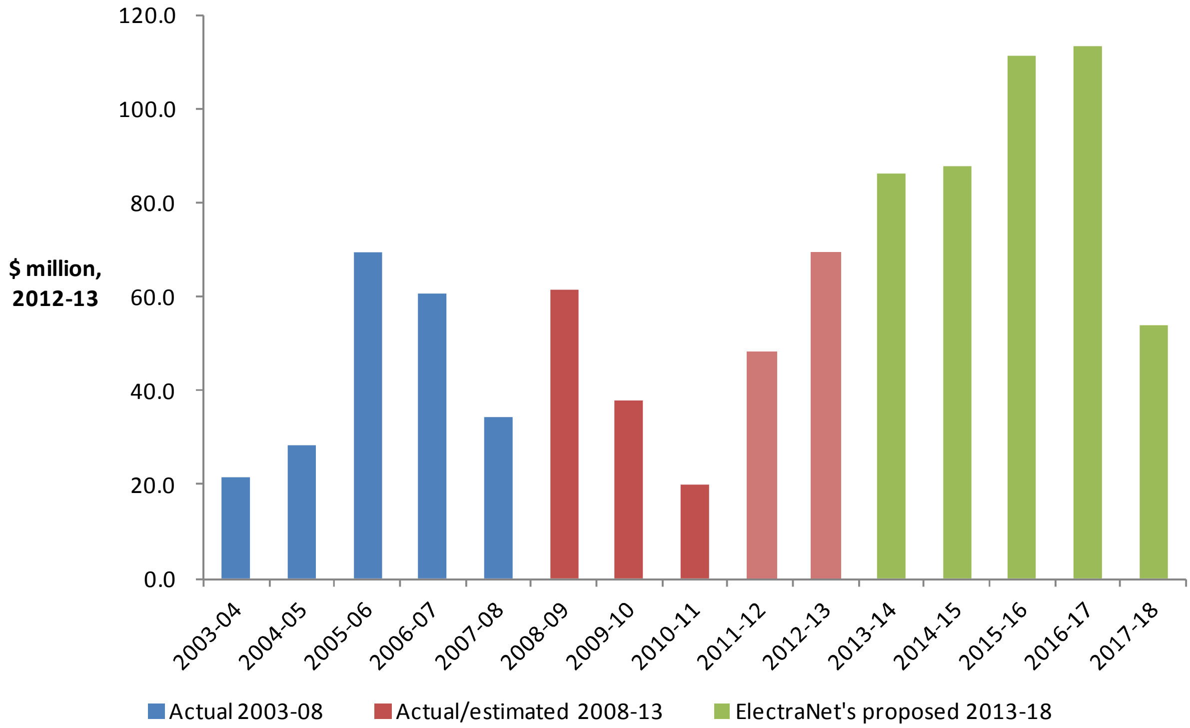
Source: ElectraNet, Response to information request AER RP 06, *ElectraNet's historic and forecast capex and opex by category in $m 2012–13*, ENET096, 26 June 2012; ElectraNet, *Annual regulatory financial report 2011–12*.

Consistent with ElectraNet's proposal, the AER observes that the increased opex and replacement / refurbishment capex is largely driven by ElectraNet's improved asset management framework. This attachment sets out the AER's consideration of ElectraNet's improved asset management framework. In particular, the AER considered the 'integrated asset management framework' and its implications on forecasting opex and capex expenditures.[266]

The key issue for the AER is whether ElectraNet's improved asset management framework, which drives significant expenditure increases, results in efficient expenditure forecasts consistent with a prudent operator.[267]

265 Attachment 5 of this draft decision sets out the opex increases by category.
266 Opex and capex criteria, NER, clauses 6A.6.6(c) and 6A.7(c).
267 NER, clauses 6A.6.6(c) and 6A.6.7(c).

Figure 3.2 ElectraNet's actual and proposed replacement / refurbishment capex ($ million, 2012–13)



Source: ElectraNet, Response to information request AER RP 06, *ElectraNet's historic and forecast capex and opex by category in $m 2012–13*, ENET096, 26 June 2012.

3.1 Draft decision

The AER considers ElectraNet's integrated asset management framework design and structure is consistent with good industry practice and that the investment in the framework is capable of delivering material benefits to ElectraNet and its customers. However, ElectraNet has not sufficiently factored the expected benefits of the framework into is regulatory proposal. ElectraNet's high level management decisions have not yet been fully informed by its framework and therefore expenditures have not been adequately justified under its comprehensive governance systems. As a result, the proposal is overstated and does not satisfy the opex and capex criteria.[268]

ElectraNet has not assessed the economic benefits of its asset management framework on a whole of program basis. It has also not assessed the economic benefits of reducing maintenance expenditure by undertaking targeted replacements. Nor has it shown the economic benefits of deferring replacements by increasing opex. In the absence of such assessments, the AER considers that the expenditure forecasts do not satisfy the efficiency and prudency requirements set out in the opex and capex criteria.[269]

The AER accepts that condition based asset management is an appropriate approach for managing transmission assets. ElectraNet's integrated asset management framework applies the principles of condition based asset management and is a fundamental component of its strategic approach to managing its network. In this context, although the full economic benefits have not been demonstrated, the AER has approved scope changes to the field maintenance opex category. This

268 NER, clauses 6A.6.6(c) and 6A.6.7(c).
269 NER, clauses 6A.6.6(c) and 6A.6.7(c).

has resulted in an opex allowance increase above the revealed cost trend. The AER's assessment of opex is set out in attachment 5.

At the same time, the AER expects that ElectraNet's expanded and improved field maintenance program in combination with its asset management framework ought to lead to lower replacement capex in the future. That is, the AER considers that ElectraNet should to be able to defer at least $50 million of replacement capex in the 2013–18 regulatory control period.[270] The AER considers that increased opex (due to the integrated asset management framework) and reduced capex (benefits of the integrated asset management framework) allowances are interrelated. The higher costs incurred by ElectraNet in developing and applying its new system cannot stand alone without considering the benefits that are likely to arise. The AER has therefore made a capex/opex trade-off adjustment and the reasons for this adjustment are discussed in this attachment.

3.2 ElectraNet's proposal

ElectraNet stated that its performance so far over the 2008–13 regulatory control period exhibits an overall level of high performance. It considers that it has responded positively to regulatory incentives resulting in cost savings in the early years and also some long-term sustainable savings. Nevertheless, it proposed that these costs savings will be overtaken by cost increases due to a number of cost drivers. In particular, it noted the initiatives aimed at improving long-run asset performance. This included the introduction and implementation of an expanded maintenance regime to address fire start risk and asset condition, and a more structured asset data collection and analysis system.[271]

Noting the age of its transmission assets (substations and lines), ElectraNet submitted that:[272]

> ... essential that ElectraNet maintains existing service capacity by undertaking prudent maintenance expenditure to efficiently prolong asset life as long as possible, and plan for the replacement of assets where this results in lowest long-run costs. If timely action is not taken, maintaining service reliability will become an insurmountable challenge as the risk of asset failures increase and cost of maintenance in future will be considerably higher.

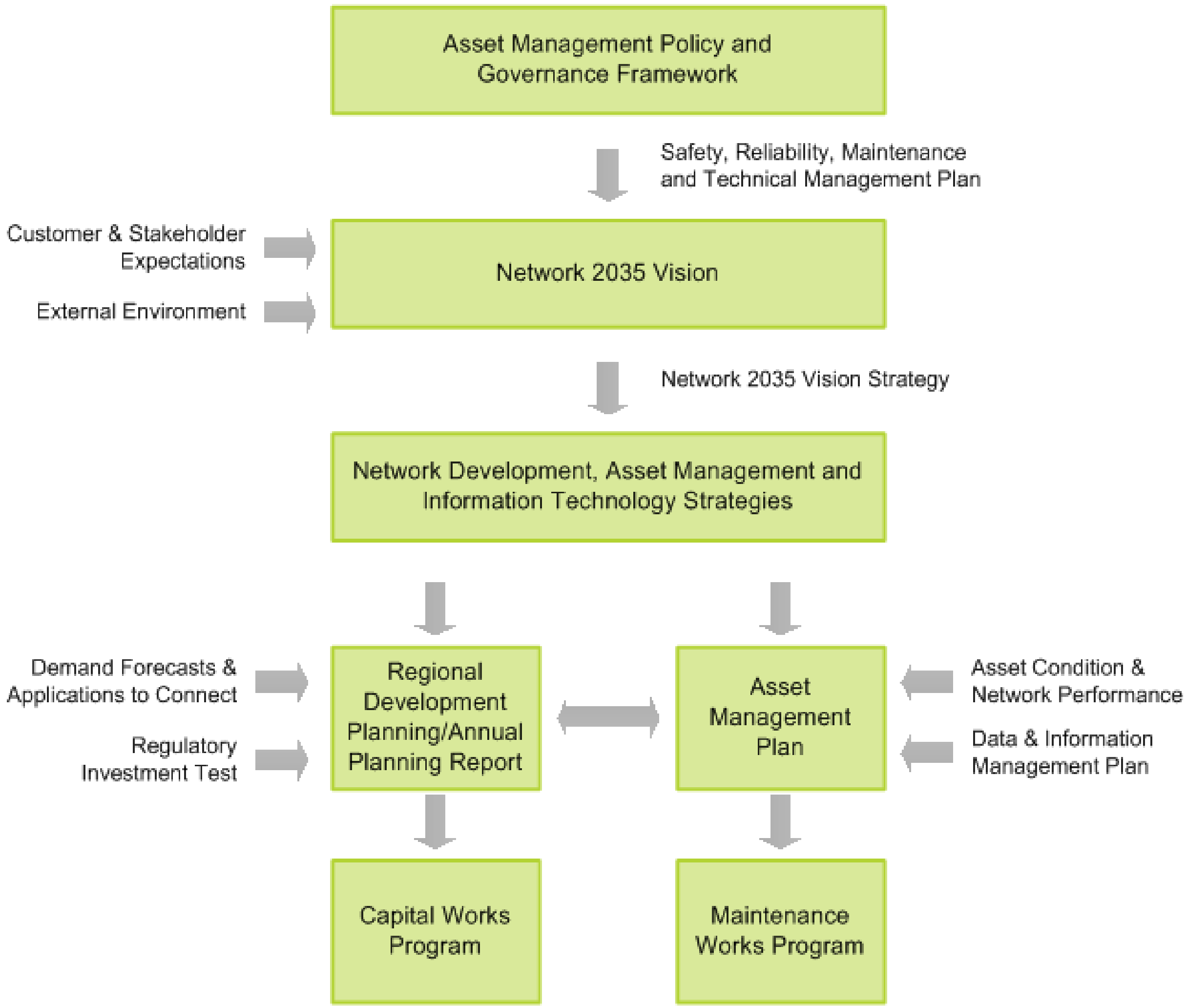
ElectraNet's strategic framework response to these cost drivers is developed through its Network 2035 vision document.[273] Figure 3.3 shows the relationship between this vision and network planning and operational activities.

Guided by its 2035 vision document, ElectraNet's approach to efficient and effective asset management is set out in its Board approved asset management strategy document.[274] ElectraNet's asset management strategic priorities for the 2013–18 regulatory control period are: data and information management; network management; and substation, transmission line and telecommunication asset management.[275] To deliver on these priorities, ElectraNet has developed its asset management plan (AMP). The AMP states that it has been developed within a strategic planning framework that included taking direction from the organisational policy, a long-term vision and Board approved strategies for network development, asset management and information technology.[276] This plan is built on a risk based approach to manage the lifecycle of each transmission

270 NER, clause 6A.14.1(2)(ii).
271 ElectraNet, *Revenue proposal*, p. 3.
272 ElectraNet, *Revenue proposal,* p. 6.
273 ElectraNet, *Revenue proposal,* p. 33.
274 ElectraNet, *Revenue proposal,* appendix E – Asset management strategy.
275 ElectraNet, *Revenue proposal,* p. 93.
276 ElectraNet, *Asset management plan,* May 2012, p. 8.

asset to maintain acceptable levels of reliability and performance at the lowest possible long run cost.[277] This approach is referred to by the AER as the integrated asset management framework.

Figure 3.3 ElectraNet's integrated asset management framework



Source: ElectraNet, *Asset management plan*, May 2012, p. 12.

3.3 Assessment approach

In assessing ElectraNet's integrated asset management framework the AER considered the standard of the framework, cost of deployment and implementation and inherent capabilities of such an asset management framework.

The AER's consultant Energy Market Consulting associates (EMCa) undertook an extensive review of ElectraNet's proposal including on-site visits and numerous information requests. Its approach to the review was twofold, first it reviewed ElectraNet's asset management framework through which the capex and opex proposals are developed. Second, EMCa undertook a detailed review of sample projects to assess the extent to which ElectraNet's asset management framework is applied in practice. EMCa's approach is set out in its report.[278]

277 ElectraNet, *Revenue proposal*, p. 93.
278 EMCa, *ElectraNet technical review*, October 2012, pp, 43–45.

The AER is satisfied with the breadth and depth of the review undertaken by EMCa in its review of ElectraNet's revenue proposal and therefore has placed considerable weight on its advice.[279] Furthermore, consistent with the AER's consultative approach to investigating issues, on 3 October, 2012, the AER facilitated a workshop between EMCa, ElectraNet and AER staff to robustly engage with ElectraNet on EMCa's findings. Subsequently, EMCa provided an addendum to its technical report.[280]

3.4 Reasons for draft decision

The AER's capex / opex trade-off adjustment has been made in the context of ElectraNet's integrated asset management framework and its implications for forecasting expenditure. Therefore, the AER's reasons are discussed in relation to this framework and are set out below under the following sub headings:

- design and structure
- deployment and implementation
- economic analysis
- capex /opex trade-off.

The AER received four submissions on ElectraNet's proposal. Most of the submissions expressed concerns regarding the magnitude of ElectraNet's proposed opex and capex increases and highlighted the need for further review. The SACOSS submission noted the increase in opex between the 2008–13 and 2013–18 regulatory control periods.[281] The EUAA questioned the extent to which ElectraNet’s opex proposal involves a ‘trade off’ with its capex proposal and whether this is justified. It also questioned whether ElectraNet is employing best practice asset management, the evidence for this and whether its expenditures are justified.[282]

3.4.1 Design and structure

The AER accepts that ElectraNet's integrated asset management framework design and structure is consistent with good industry practice. This framework is a condition and risk based total asset life cycle management approach and is based on:

- comprehensive asset condition intelligence and data
- risk assessment driven work prioritisation
- an optimisation model based on total asset life cycle.[283]

Three core systems and methods underpin the integrated asset management framework:

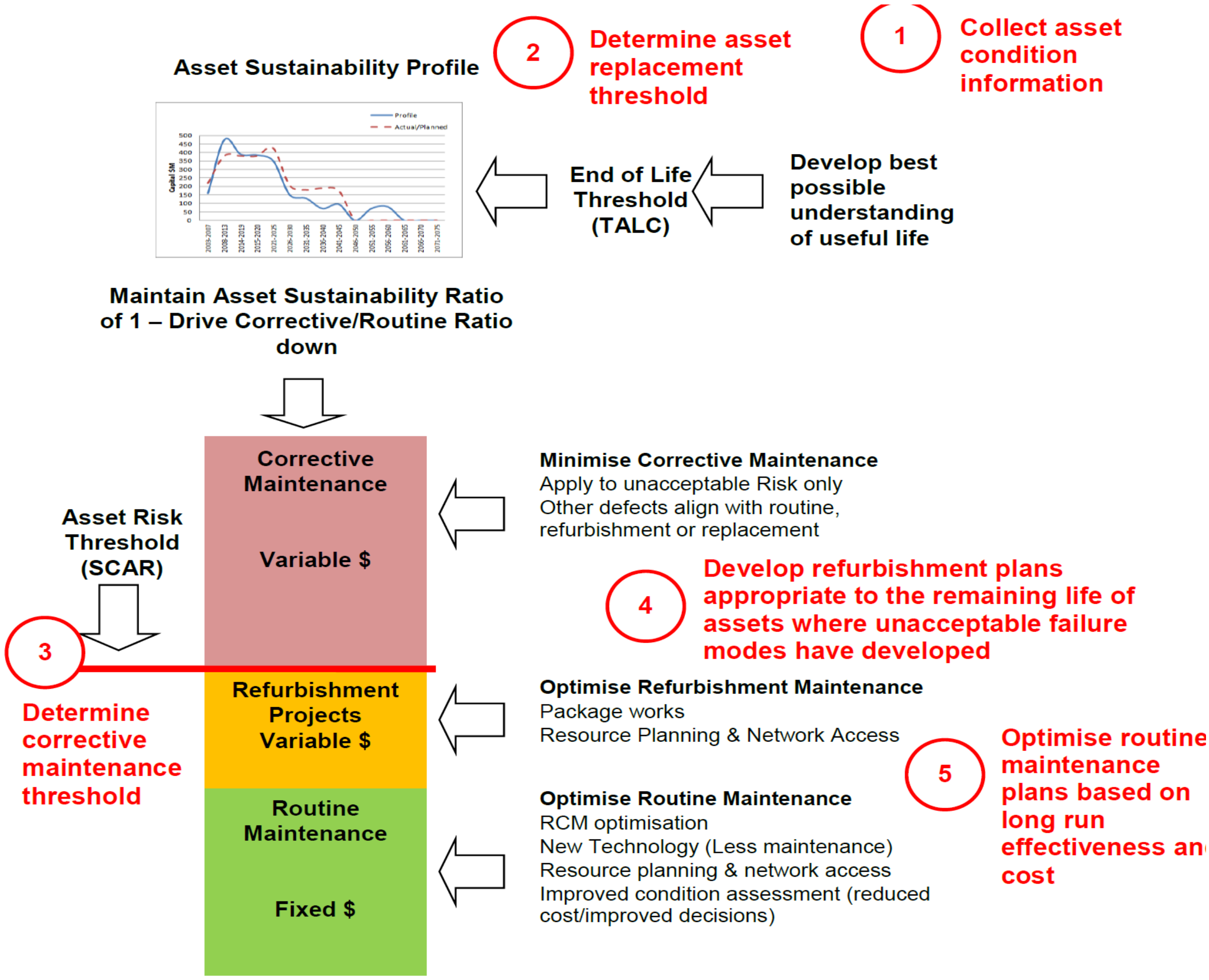
- asset condition data acquisition and management (SAP database)
- system condition and risk (SCAR)

[279] EMCa, *ElectraNet technical review*, October 2012, Annexure C – Resume of authors.
[280] EMCa, *ElectraNet technical review*, October 2012, Annexure D – Addendum: Implications arising from additional engagement with ElectraNet.
[281] SACOSS, *Submission to the Australian Energy Regulator Consultation on ElectraNet’s 2013–18 Transmission Network Revenue Proposal*, August 2012 ,p. 4.
[282] EUAA, *Submission on ElectraNet's revenue proposal 2013–18,* August 2012, p. 12.
[283] EMCa, *ElectraNet technical review*, October 2012, p. 49.

- total asset life cycle (TALC).[284]

Figure 3.4 demonstrates ElectraNet's asset maintenance / replacement decision framework.

Figure 3.4 ElectraNet's asset maintenance /replacement decision framework



Source: ElectraNet response, *Capex replacement and maintenance decision framework*, ENET 271, pp. 6–9 October , 2012

EMCa advised that ElectraNet has adopted and built on well proven asset management strategies and systems, and is able to demonstrate that it has intelligent asset management strategies supported by increasingly reliable data.[285] EMCa further noted that the systems adopted demonstrate that asset management strategies can be optimised against defined risk profiles.[286]

The AER agrees with EMCa that condition-based maintenance regimes can facilitate lifecycle management of risks in a transparent and cost-effective manner. Such frameworks allow the measurements of trade-offs between expenditure and risks including measuring project level risks for given levels of expenditure. Further, they allow for assessments of future cost implications of pulling forward or deferring corrective maintenance and refurbishment/replacement, using economic analysis such as net present value calculations.[287] However, ElectraNet has not provided evidence of such

284 EMCa, *ElectraNet technical review*, October 2012, p. 49.
285 EMCa, *ElectraNet technical review*, October 2012, p. 60.
286 EMCa, *ElectraNet technical review*, October 2012, p. 52.
287 EMCa, *ElectraNet technical review*, October 2012, p. 120.

economic analysis and therefore, although recognising the risks, it has not considered the cost of minimising risk nor the economic benefits of such action.[288]

3.4.2 Deployment and implementation

The AER considers that ElectraNet's deployment and implementation of its integrated asset management framework is not sufficiently justified in terms of the stated asset management strategy. ElectraNet is progressively implementing its integrated asset management framework and it may not yet be producing fully optimised outputs. However, ElectraNet ought to have more fully utilised its current capabilities (which are significant).

In the context of the corrective maintenance program assessment, EMCa made the following observations on ElectraNet's integrated asset management framework:

- EMCa indentified significant costs arising from implementing and deploying this framework in the 2013–18 regulatory control period
- the justification for the framework is weak. There has not been adequate justification for risk/cost trade-offs or current cost/future cost trade-offs that are inherent in the proposed maintenance, refurbishment and asset replacement programs. EMCa did not accept the argument that these programs are insensitive to risk and only high risk conditions are being addressed.
- the asset condition data base that is being developed to support the regime is comprehensive and therefore costly. With full analysis of costs and options, the majority of benefits could be achieved with considerably lower deployment costs by relying on sampling and asset type focus.[289]

The AER considers that consistent with ElectraNet's asset management strategy the deployment and implementation of the integrated asset management framework should be leading to lower long run costs. In the absence of this evidence the AER is not satisfied that the asset management decisions are consistent with ElectraNet's Board approved strategy. The AER accepts EMCa's conclusion that TALC asset management methods such as those adopted by ElectraNet are intended to provide objective decision making when considering appropriate action for specific assets.[290] The AER does not have sufficient evidence before it to see whether there has been such objective decision making based on economic analysis across ElectraNet's decision making chain.

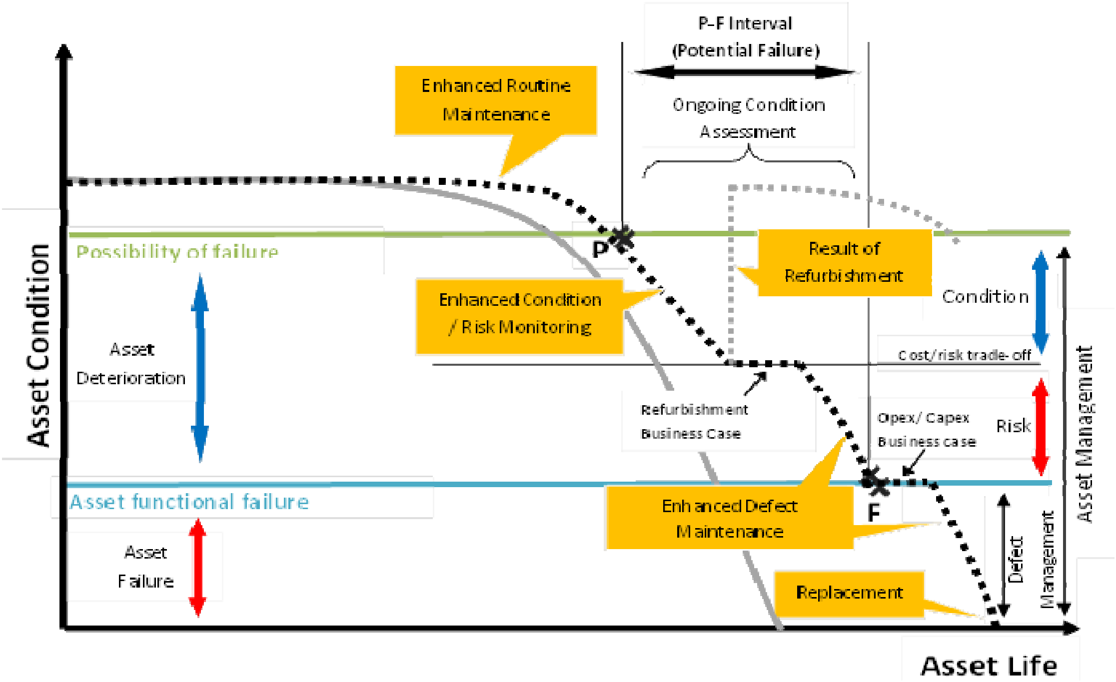
EMCa investigated how expenditure and risk implications were taken into account when making adjustments to forecast expenditure. It specifically attempted to understand the basis on which expenditure was demarcated and how risks were accounted for by ElectraNet in developing expenditure forecasts. EMCa was not satisfied that ElectraNet applied the TALC method at a mature level. It concluded that ElectraNet did not provide evidence to show that the TALC was used at all levels of the organisation and noted that it was unclear whether TALC was used to fully inform senior management decisions.[291]

The AER considers that under the integrated asset management framework, costs can be optimised (minimised) through consideration of the asset reliability curve. Essentially, the application of each expenditure strategy will change the shape of the curve. In essence, this allows ElectraNet to undertake "threshold" analysis of cost/risk and economic trade-offs.[292] This is an inherent capability of

[288] EMCa, *ElectraNet technical review*, October 2012, p. 119.
[289] EMCa, *ElectraNet technical review*, October 2012, p. 120.
[290] EMCa, *ElectraNet technical review*, October 2012, p. 57.
[291] EMCa, *ElectraNet technical review*, October 2012, p. 57.
[292] EMCa, *ElectraNet technical review*, October 2012, Annexure D – Addendum: Implications arising from additional engagement with ElectraNet, p. D-5.

this asset management approach and the AER considers that ElectraNet is able to calculate the economic benefits when making its decisions. The AER expects that accounting for these benefits will have a material impact on expenditure forecasts. Evidence of such decision making was not presented to the AER.[293] Figure 3.5 shows how the "asset reliability" curve (grey) is shifted (black dash) depending on the timing of the expenditure strategy (yellow).

Figure 3.5 Asset reliability curve and expenditure strategy



Source: EMCa, *ElectraNet technical review*, October 2012, p. 98.

3.4.3 Economic analysis

The AER considers that an economic analysis of the cost of deployment and implementation of the integrated asset management framework would demonstrate the economic benefits of this framework. That is, it should show that this framework results in lower long run costs consistent with ElectraNet's asset management strategy.

EMCa stated:[294]

> Our view remains that justification, in terms of quantified and realistic benefits is required for the levels of increased maintenance and replacement that have been proposed, and this has not been provided. This would not only assist the regulator, but we consider that it would also be a matter of good governance to undertake such a "mid-implementation review" in order to confirm the direction that ElectraNet is taking and to set objective and measurable benefit targets.

Implicit in this integrated asset management framework is whole of asset life economic optimisation. The ability to better manage opex/capex trade-offs delivers economic gains without increasing acceptable asset failure risks. That is, opex activities are undertaken to defer the need for replacement or refurbishment capex whereby the increase in opex to undertake this activity produces

[293] ElectraNet, *Response to EMCa information request EMCa 17 – Capex/opex budget process*, ENET 168, July 2012.
[294] EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-6.

a decrease in capex. However, EMCa considers that in practice this is not demonstrated in ElectraNet's revenue proposal:[295]

> For a positive benefit to be derived from the adoption and implementation of SCAR and TALC it would be expected that at least the costs of the framework would be recovered over a reasonable time horizon. Yet in the proposal we are seeing an increase in opex without a realisation of the benefits in replacement/refurbishment capex, which are also increasing.

The AER and EMCa requested ElectraNet's business case for developing and implementing the integrated asset management framework.[296] ElectraNet responded that the integrated asset management framework developed from an asset data and information management plan in 2008 and that it approved the program's implementation via annual business unit plans and budgets.[297] ElectraNet did not provide evidence that showed it had quantified the benefits to be achieved and their timing, the all-up cost or the total estimate of the resources required.[298] Further, it did not identify the benefits and timing of the program as a whole. ElectraNet did provide evidence from 2008 that it was projecting a decline in reliability and functionality risks.[299] It also indicated that only defects with safety / environment or reliability / availability are considered for corrective maintenance. But, it did not demonstrate the benefits of reducing such risks against the costs, and did not articulate the economic value of the costs.[300]

Having considered EMCa's advice, the AER is satisfied that:

- the asset replacement threshold is developed without reference to economic analysis[301]
- a significant number of defects that drive corrective maintenance are "asset related" and do not have safety / environment or reliability / availability impacts. Decisions relating to corrective maintenance of "asset risks" necessarily involve engineering economic trade-offs.[302] ElectraNet suggested that only defects with safety / environment or reliability / availability are considered for corrective maintenance. EMCa found that this category of defect "notis" were about 45 per cent of all "notis" and the rest were "asset risks" which present a risk of asset component failing but without the safety / environment or reliability / availability impacts.[303]
- ElectraNet has not provided information about the cut-off points at which asset refurbishment projects are undertaken to justify the cost/risk (asset lifecycle economics) to understand the financial implications of these decisions.[304]

ElectraNet claimed that its approach has allowed delaying replacements in excess of $3.5 billion over that would otherwise be required over two regulatory control periods (compared with the original asset replacement plan based on age profile and limited condition assessment).[305] EMCa considered this claimed deferral benefit as implausible relative to its actual replacement capex in the 2008–13 regulatory control period and proposed replacement capex in its revenue proposal.[306]

295 EMCa, *ElectraNet technical review*, October 2012, p. 99.
296 EMCa, *Information request EMCa 14 and 15*, July 2012.
297 ElectraNet, *Response to EMCa information request EMCa 14 and 15,* ENET 180, July 2012.
298 EMCa, *ElectraNet technical review*, October 2012, p. 119.
299 ElectraNet, *Response to EMCa information request EMCa 14 and 15,* ENET 180, July 2012.
300 ElectraNet, *Response to EMCa information request EMCa 26,* ENET 182,185 and 201, July 2012.
301 EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-5.
302 EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-5.
303 EMCa, *ElectraNet technical review*, October 2012, p. 123.
304 EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-5. .
305 ElectraNet response to matters raised at 3 October meeting, *Capex replacement and maintenance decision framework*, ENET 271, October 2012, p. 9.
306 EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-6.

The AER recognises the need to make risk based decisions and encourages programs that enable such decision making. However, such decision making must take into account the cost of such decisions and ensure that customers and service providers share in the cost / risk trade-off.

In the absence of ElectraNet providing the economic analysis, EMCa estimated the cost of designing and implementing the integrated asset management framework at $52.7 million ($2012–13). This is an incremental cost estimate relative to what would have been incurred in the absence of the regime.[307] Table 3.1 sets out EMCa's estimates of these costs by category.

While the AER does not conduct ex-post reviews, it expects that a prudent TNSP making such a significant investment in a new framework should have a clear economic case for the strategic move. The AER considers it reasonable to expect that ElectraNet's investment in its integrated asset management framework should have positive net benefits which should be accounted for in forecasting expenditure under the NER requirements.[308]

Table 3.1 Estimate of incremental cost of deployment ($ million, 2012–13)

Cost category	2008–13	2013–18	Total
Routine maintenance	9.0	15.0	24.0
Operational refurbishment	4.9	15	19.9
Asset manager support	2.4	5.4	7.8
Total opex	16.3	35.4	51.7
Capex (IT)	1.0	-	1.0
TOTAL	17.3	35.4	52.7

Source: EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-5.

In developing its alternative expenditure forecast the AER has taken account of EMCa' estimate of the costs. The AER considers that a prudent TNSP would consider the benefits of its move to an integrated asset management framework with a view to recovering a break-even amount of the costs over a reasonable time horizon. The AER's draft decision will recover these costs over the 2013–18 regulatory control period which is the period applicable to this transmission determination. The AER considers that this recovery time horizon is reasonable as it understands that ElectraNet's progressive move to this framework commenced around 2008.[309]

3.4.4 Capex / opex trade-off

The AER's substitute capex forecast for ElectraNet will defer $50 million in replacement capex to account for the economic benefits of the integrated asset management framework.[310] The AER considers that such an approach is consistent with the capex criteria and the NEO.[311] That is, an efficient forecast made on a prudent basis would not only take account of the risks and costs of mitigating risks but also the benefits in terms of asset lifecycle economics.

In the absence of such an adjustment, customers would be underwriting all of the implementation costs associated with the integrated asset management framework without the benefits being

307 EMCa, EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-6.
308 NER, clauses 6A.6.6(c) and 6A.6.7(c) and National Electricity Objective.
309 ElectraNet, *Response to EMCa information request EMCa 14 and 15,* ENET 180, July 2012.
310 The adjustment for as incurred capex for 2013–18 regulatory control period is approximately $50.1 million ($2012–13).
311 NER, clauses 6A.6.6(c) and 6A.6.7(c).

recovered via transmission prices over a reasonable timeframe. Moreover, not accounting for the benefits would result in any risk associated with the strategic decisions being solely borne by customers.

In this instance the AER has provided for a scope change in opex to account for a step change in opex going forward in recognition of ElectraNet already having committed to the integrated asset management framework. To the extent that ElectraNet can achieve further opex efficiencies it can recover those via the Efficiency Benefit Sharing Scheme. Hence, accounting for the inherent economic benefits via a capex adjustment does not undermine the opex incentive framework. In the absence of this capex adjustment, ElectraNet will not only recover the implementation cost of this program but also recover the economic benefits inherent in the capex/opex trade off which it has not accounted for in its expenditure forecast. The AER considers that such an approach is inconsistent with the NEO, in that, it does not recognise the long term interests of customers.[312]

The AER considers that ElectraNet has the potential to achieve significant benefits from its new system. In the absence of sufficient evidence from ElectraNet, the AER considers that the $50 million capex adjustment is reasonable and a conservative approach to accounting for potential economic benefits.

3.5 Revisions

Refer to revision 4.1 in attachment 4 for the capex/opex trade-off reduction to forecast capex.

312 NEL, section 7.

4 Capital expenditure

Forecast capital expenditure (capex) is a forecast of the cost of new assets that a network business is likely to require during a regulatory control period to operate the network efficiently. Capex is typically broken down into network and non-network related categories:

- network load driven — augmentation, connection and land/easements
- network non-load driven — replacement, refurbishment, security/compliance and inventory spares
- non–network — business IT and buildings/facilities.

ElectraNet is required to submit a building block proposal to the AER that forecasts capex for the 2013–18 regulatory control period.[313] The AER must either accept ElectraNet's proposed forecast capex allowance or determine a substitute forecast.[314]

This attachment outlines the AER's draft decision, its reasoning and its approach to assessing ElectraNet's proposed capex forecast and for deriving the substitute forecast.

4.1 Draft decision

The AER does not accept the forecast total required capex of $894.1 million ($2012–13) proposed by ElectraNet for the 2013–18 regulatory control period.[315] It is not satisfied the proposed forecast reasonably reflects the capex criteria because it considers ElectraNet has overstated elements of the forecast.[316] The AER has thus estimated a substitute forecast capex that reasonably reflects the NER requirements and the AER's draft decision demand forecast.[317] The AER has made adjustments to the following components of ElectraNet's capex forecast to develop its substitute forecast as required under the NER:[318]

- cost estimation risk factor—$19.6 million ($2012–13) reduction
- replacement and refurbishment capex—$81.8 million ($2012–13) reduction
- real cost escalation—$9.3 million ($2012–13) reduction
- strategic land and easement acquisitions—$51.4 million ($2012–13) reduction
- load driven capex—$103.7 million ($2012–13) reduction.

Table 4.1 summarises the substitute forecast capex that the AER considers ElectraNet requires over the 2013–18 regulatory control period. The AER has estimated a forecast capex of $641.9 million ($2012–13), which represents a reduction of $252.3 million ($2012–13) (or 28.2 per cent) on ElectraNet's proposal.

313 NER, clause 6A.10.1.
314 NER, clauses 6A.6.7(c) and (d).
315 NER, clause 6A.14.1(2)(ii).
316 NER, clause 6A.6.7(c).
317 NER, clause 6A.14.1(2)(ii).
318 NER, clause 6A.14.1(2)(ii), NER, clause 6A.6.7(c), NEL, s.7 and s.7A.

Table 4.1 AER's draft decision on ElectraNet's forecast total capex ($ million, 2012–13)

	Incremental adjustment	Aggregate adjustment	Total capex
ElectraNet forecast capex			**894.1**
Cost estimation risk factor		**19.6**	
0% replacement/refurbishment	–16.2		
2.6% augmentation/connection	–2.9		
2.6% all other capex	–0.5		
Prudency		**50.1**	
Replacement/refurbishment	–31.7		
Capex / opex trade-off		**96.7**	
Replacement/refurbishment	–50.1		
Real cost escalators	-9.3	**105.2**	
Strategic land and easements acquisitions	–51.4	**157.4**	
Demand adjustments		**252.3**	
Connection	–29.6		
Augmentation	–17.6		
Replacement	–56.5		
Adjusted forecast capex			**641.9**

Sources: AER analysis, EMCa analysis.

Table 4.2 shows the AER’s draft decision in more detail.

Table 4.2 AER draft decision on ElectraNet's forecast total capex allowance–by category ($ million, 2012—13)

Capex category	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Augmentation	37.4	17.4	11.2	12.5	20.2	**98.7**
Connection	49.8	17.2	17.2	11.7	5.9	**101.7**
Replacement	66.5	54.0	54.2	63.2	23.7	**261.6**
Refurbishment	0.9	4.9	23.4	11.5	1.4	**42.2**
Strategic land /easements	4.4	0.2	0.3	1.1	7.5	**13.4**
Security /compliance	9.9	10.8	16.6	11.6	8.1	**56.9**
Inventory/spares	4.6	3.7	4.6	3.0	2.1	**18.0**
Total network	**173.6**	**108.1**	**127.5**	**114.5**	**68.9**	**592.6**
Business IT	8.9	10.7	11.4	7.2	5.5	**43.7**
Building/facilities	0.7	1.4	2.1	0.6	0.6	**5.4**
Total non–network	**9.6**	**12.2**	**13.5**	**7.9**	**6.1**	**49.3**
Total capex	**183.2**	**120.3**	**141.0**	**122.4**	**75.0**	**641.9**

Source: AER analysis. Note these figures are "as incurred". Numbers may not add due to rounding.

The AER assessed key factors underpinning ElectraNet's proposed total forecast capex. A key issue the AER found was that Electranet had not sufficiently factored the expected benefits of its integrated asset management framework into its capex proposal (see attachment 3). Specifically ElectraNet did not show the economic benefits of increasing opex associated with implementing its integrated asset management framework. Thus the AER considers ElectraNet had been overly cautious in its proposal by not taking these into account. The AER has applied an adjustment to replacement capex (capex/opex trade–off adjustment) to reflect these benefits.

The AER also considers ElectraNet's asset management framework impacts on other components of ElectraNet's capex proposal namely the cost estimation risk factor and other areas of ElectraNet's replacement and refurbishment capex. The AER has made adjustments to reflect these considerations.

In addition, the AER made adjustments to reflect its draft decision for real cost escalation, land and easement capex and the impact of its demand forecast on Electranet's load driven capex.

4.2 ElectraNet's proposal

ElectraNet proposed a forecast total required capex of $894.1 million ($2012–13) (Table 4.3) up 1.3 per cent on estimated capex incurred over the 2008–13 regulatory control period.[319]

[319] The 2008–11 capex is actual capex incurred while the 2011–12 capex is an estimate.

Table 4.3 ElectraNet's proposed forecast capex, by category ($ million, 2012–13)

Project category	Sub-category	$ million, 2012-13
NETWORK		
Load driven	Augmentation	117.9
	Connection	133.3
	Land/easements	65.8
Non-load driven	Replacement	398.0
	Refurbishment	54.1
	Security/compliance	57.3
	Inventory/spares	18.4
	Total network	844.9
NON-NETWORK		
	Business IT	43.7
	Buildings/facilities	5.6
	Total non-network	49.3
TOTAL CAPEX		**894.1**

Source: ElectraNet, *Revenue proposal*, pp. 73–74.

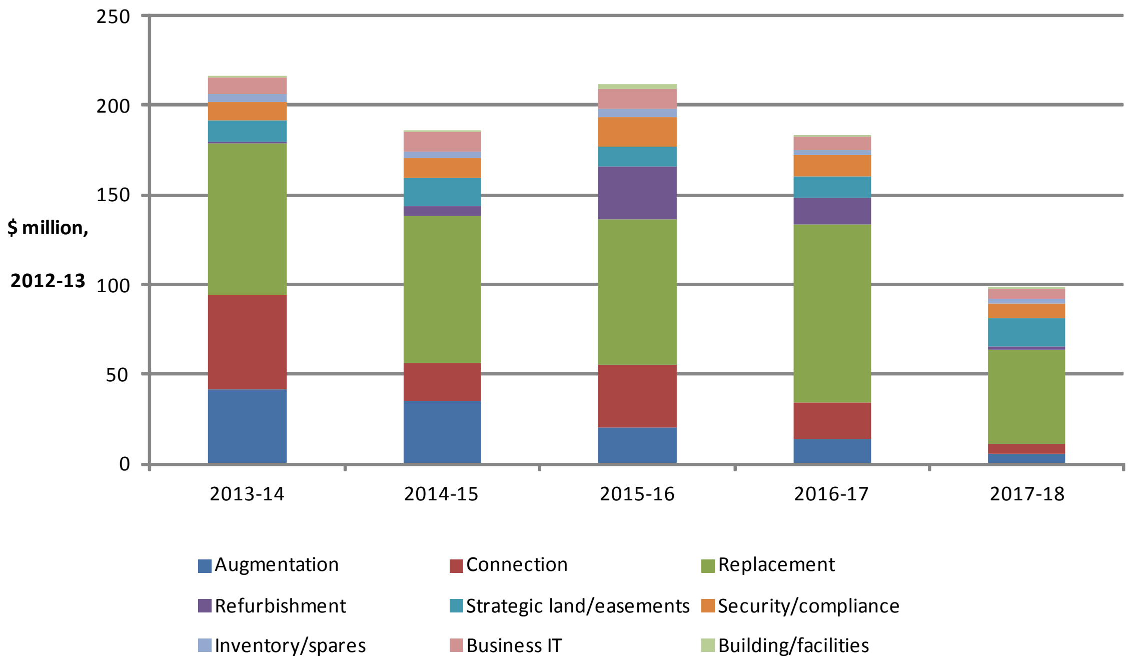
The proposed capex categories that are significantly above expenditure in the 2008–13 regulatory control period are:

- replacement—up $160.7 million ($2012–13) or 67.7 per cent
- refurbishment—up $54.1 million ($2012–13)[320]
- land and easements—up $35.8 million ($2012–13) or 119.6 per cent.

Proposed augmentation capex of $117.9 million ($2012–13) is significantly lower than the estimate from the 2008–13 regulatory control period—down by $243.9 million ($2012–13) or 67.4 per cent. Figure 4.1 and Table 4.4 sets out ElectraNet's proposed forecast capex by category and by year.

320 Refurbishment capex was not a capex category for the 2008–13 regulatory control period. The AER's 2008 determination moved some proposed opex into refurbishment capex which is reflected in ElectraNet's roll forward and post tax revenue models. A capex asset class was created but no capex category was created for refurbishment capex. For the 2013–18 regulatory control period ElectraNet has proposed refurbishment as a capex category which is reflected here.

Figure 4.1 ElectraNet's proposed forecast capex, by category and year ($ million, 2012–13)



Source: AER analysis, ElectraNet, *Revenue proposal*, pp. 73–74.

Table 4.4 ElectraNet's proposed forecast capex, by category and year ($ million, 2012–13)

Capex category	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Augmentation	41.9	35.1	20.8	14.2	5.9	**117.9**
Connection	51.8	21.2	34.2	20.4	5.6	**133.2**
Replacement	84.8	81.5	81.3	98.6	51.8	**398.0**
Refurbishment	1.2	6.3	29.8	14.8	2.1	**54.2**
Strategic land /easements	11.9	15.3	10.3	12.2	16.1	**65.8**
Security /compliance	10.0	10.8	16.8	11.6	8.1	**57.3**
Inventory/spares	4.7	3.8	4.8	3.0	2.1	**18.4**
Total network	**206.3**	**174.0**	**197.9**	**174.9**	**91.8**	**844.9**
Business IT	8.9	10.7	11.4	7.2	5.5	**43.7**
Building/facilities	0.7	1.4	2.1	0.6	0.6	**5.4**
Total non–network	**9.6**	**12.2**	**13.5**	**7.9**	**6.1**	**49.3**
Total capex	**215.9**	**186.2**	**211.4**	**182.7**	**97.9**	**894.1**

Source: ElectraNet, *Revenue proposal*, p. 76.

Underlying ElectraNet's proposed forecast capex is its integrated asset management framework (the framework). The framework comprises the policies and plans to deliver key outcomes. These policies and plans should drive the capital and maintenance work program over the 2013–18 regulatory control period. See attachment 3 for discussion of the framework, with particular reference to condition and risk based total asset life cycle management.

4.3 Assessment approach

The AER must accept ElectraNet's proposed forecast capex if satisfied it reasonably reflects the capex criteria.[321] It must form a view on the forecast capex as a whole, not as individual projects or programs.[322] However, because the total required capex is separated into expenditure components, the AER assesses these components to make its decision on the total amount.

The forecast must reflect the efficient costs that a prudent operator in ElectraNet's circumstances would need to incur, based on a realistic expectation of the demand forecast and the cost inputs to achieve the capex objectives.[323]

In deciding whether ElectraNet's proposed forecast capex reasonably reflects the capex criteria, the AER must have regard to the capex factors.[324] Although the AER considered each capex factor when assessing ElectraNet's proposed total forecast capex, not all factors were relevant to each capex component.[325]

Also in its assessment, the AER had regard to the National Electricity Objective (NEO) as well as the revenue and pricing principles in the National Electricity Law (NEL).[326] For instance, the AER reviewed ElectraNet's proposed strategic land and easement acquisitions capex to assess whether it was in the long term interests of consumers, in terms of price and reliability. This is because part of this proposed capex is not needed to meet the expected demand for prescribed transmission services until at least the 2023–28 regulatory control period.

In assessing ElectraNet's efficient costs, the AER considered a mix of top down and bottom up approaches. It assessed ElectraNet's historic capex and determined the key drivers for forecast capex. This work included analysing ElectraNet's:

- asset management framework (the framework)
- asset management policies
- business management systems and operations
- strategic planning, including policy development
- business process improvement initiatives
- investment justification processes
- major risks identified for the 2013–18 regulatory control period, and the risk management practices and policies adopted to mitigate those risks.

By examining key documents, processes and assumptions, and comparing historical expenditure to that proposed, the AER can better understand the key drivers behind ElectraNet's need to undertake capex on its network. Attachment 3 sets out the AER's review of the framework, including ElectraNet's investment decision making process. This review informed the AER's analysis of how ElectraNet applies the framework and the influence of the framework on its future capex.

321 NER, clause 6A.6.7(c).
322 NER, clause 6A.14.1(2).
323 NER, clause 6A.6.7(c). Clause 6A.6.7(a) specifies the capex objectives.
324 NER, clause 6A.6.7(d).
325 ElectraNet's capex forecast is recovered via the depreciation and return on capital in the building block regime. It covers new investments and the replacement of ageing assets to keep the high voltage transmission system operating effectively.
326 NEL, s.7 and s.7A.

The AER engaged Energy Market Consulting associates (EMCa) to help review ElectraNet's forecast capex and the demand forecast. In its review of capex, EMCa undertook a combined top down and bottom up approach to assess the framework.[327] The top down review considered whether the framework is consistent with good industry practice. It also considered whether the framework could produce prudent and reasonable capex and operating expenditure (opex) forecasts, and how the forecasts could be adjusted when the framework did not meet good industry practice. The bottom up review determined how ElectraNet applied the framework by reviewing a sample of ElectraNet's forecast projects. EMCa undertook an on-site review of ElectraNet's practices, to determine how the organisational culture affects the development of expenditure plans and how it implements these plans. Additionally, the AER and EMCa further tested their findings with ElectraNet through ongoing engagement and consultation on key issues. This included additional information requests and face to face meetings.

The AER also considered the issues raised in submissions, the most recent National Transmission Network Development Plan (NTNDP)[328] and pre-determination work undertaken by the Australian Energy Market Operator (AEMO).[329] AEMO's pre-determination work largely investigated the need for ElectraNet's augmentation, connection and contingent project capex.[330]

For the AER to be satisfied ElectraNet's overall approach to forecasting (including its planning and management strategies and policies) reasonably reflected the capex criteria, the AER and EMCa selected 25 projects for more specific analysis. These projects amounted to approximately 47 per cent of ElectraNet's forecast capex, across a mix of capex categories.

4.4 Reasons for draft decision

Overall, the AER does not accept that ElectraNet's proposed total forecast capex satisfies the requirements of the NER and NEO for the reasons outlined in this section and the forecast expenditure attachment.[331] The AER considers ElectraNet has proposed a forecast significantly above reasonable requirements. That is, ElectraNet has in a sense taken an ‘overly cautious’ approach to developing an efficient and prudent capex forecast. ElectraNet's forecast is based on an unrealistic expectation of demand and a failure to account for its own actions on continuous improvement. Thus, the AER has made adjustments to the following components of ElectraNet's capex forecast to develop its substitute forecast as required under the NER:[332]

- cost estimation risk factor
- replacement and refurbishment capex
- real cost escalation
- strategic land and easement acquisitions
- load driven capex.

The AER's detailed reasons are discussed below.

327 EMCa, *ElectraNet technical review*, October 2012, pp. 43-107.
328 AEMO, *2011 National Transmission Network Development Plan* (NTNDP).
329 AEMO, *2012 ElectraNet revenue cap review: capital projects assessment report*, 4 June 2012.
330 AEMO's *2012 ElectraNet revenue cap review: capital projects assessment report* is available at http://www.aemo.com.au/Electricity/Planning/Reports/South-Australian-Advisory-Functions/ElectraNet-Revenue-Cap-Review
331 NER, clauses 6A.14.1(2)(ii) and 6A.6.7(c); NEL, ss. 7 and 7A.
332 NER, clauses 6A.14.1(2)(ii) and 6A.6.7(c); NEL, ss. 7 and 7A.

4.4.1 Asset management framework

The AER's assessment of ElectraNet's asset management framework (i.e. polices, governance, methods, documentation etc.) is relevant to forming a view on whether the proposed capex forecast is reasonable. The AER's consideration of key components of ElectraNet's asset management framework is discussed below.

Past capex

Any adjustments to past capex are outside the AER's scope under the NER.[333] However, the AER has reviewed ElectraNet's past capex in considering the forecast expenditure proposed for the 2013–18 regulatory control period. This review will assist the AER to form a view on ElectraNet current asset management methodologies and governance and how they are put into practice. This information is important in forming a view and making judgments on whether forecast allowances are efficient and prudent. The ECCSA agree with this approach of reviewing actual capex to understand the ElectraNet's forecast capex proposal.[334]

Overall, the AER considers ElectraNet applies good asset management methodologies and governance practices. However, the AER notes two issues arising out of ElectraNet's past capex:

- spending to the AER's allowance although demonstrating it can incur capex more efficiently
- compositional change of the total capex.

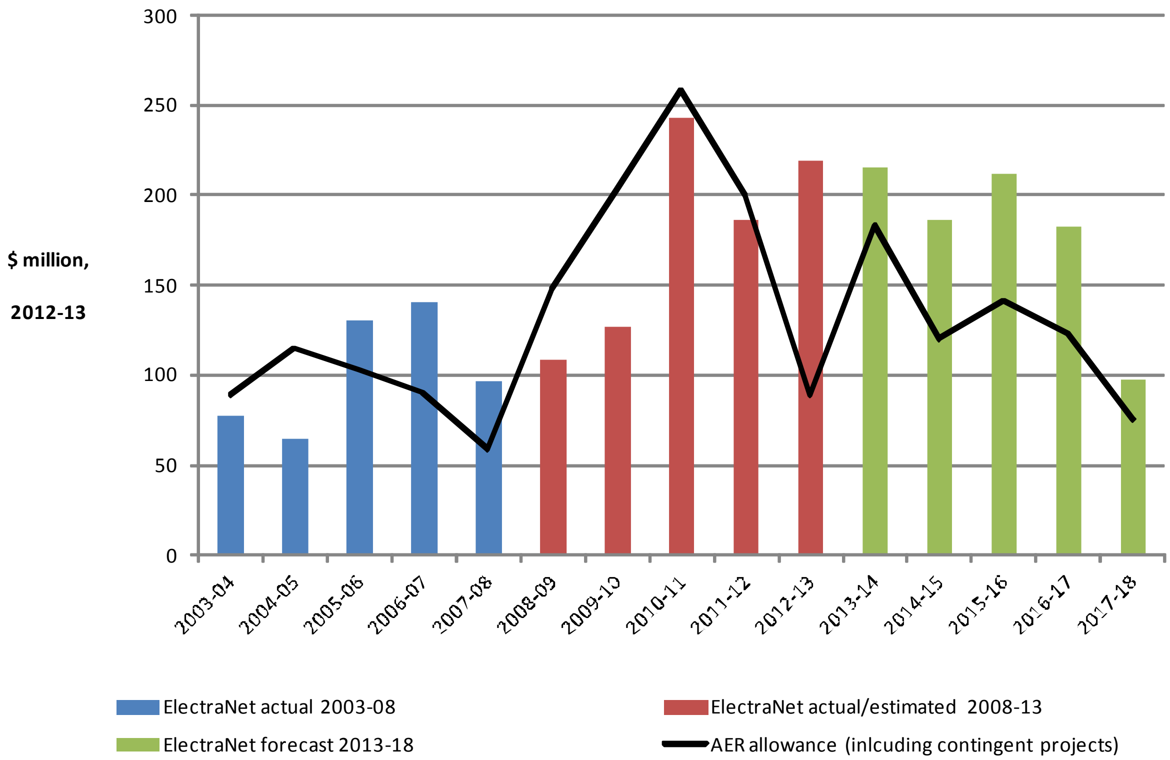
ElectraNet has demonstrated an ability to make prudent and efficient management decisions by successfully deferring or reducing capex and a capacity to achieve efficiency improvements. However, it appears at times ElectraNet overrides its own governance framework and incurs expenditures that are higher than necessary. This is particularly evident towards the end of regulatory control periods when ElectraNet is required to submit its revenue proposal. ElectraNet's revenue proposal stated:[335]

> ElectraNet has managed changing network priorities within the AER's approved capital expenditure allowance, and has made prudent investment decisions in the light of the actual circumstances that have eventuated over the course of the regulatory control period.

EMCa also noted ElectraNet's ability to make 'prudency and efficiency' savings by underspending its capex allowance in the first three years of the 2008–13 regulatory control period.[336] This outcome is evident in ElectraNet's historical capex spends. Figure 4.2 compares ElectraNet's actual, estimated and forecast capex for the 2003–08, 2008–13 and 2013–18 regulatory control periods, and the AER's allowance.[337]

333 NER, clause 6A.2.1(f).
334 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 21.
335 ElectraNet, *Revenue proposal*, p. 3.
336 EMCa, *ElectraNet technical review*, October 2012, p. 36, paragraph 84.
337 The 2003–08 regulatory control period went from 1 January 2003 to 30 June 2008. Figure 4.2 does not present the first six months of that period.

Figure 4.2 Comparison of ElectraNet's capex and the AER's allowance ($ million, 2012–13)



Source: AER analysis. The AER allowance only includes contingent projects that were triggered. ElectraNet's 2011–12 regulatory account actuals have not been used in this analysis. This will be updated for the AER final decision.

Figure 4.2 demonstrates that ElectraNet was able to defer or reduce its capex early in the regulatory control period. However, these early period deferrals and reductions are offset through higher spending in the later years. The AER recognises the incentive regulatory framework allows for the deferral of capex. However, the AER does not consider that should equate to overriding good commercial practice in later years. It is meant to compliment good commercial practice by driving efficiencies. EMCa agreed and considered ElectraNet appears to manage its capex allowance with a view to rolling forward the full allowance into the next regulatory control period.

EMCa observed that ElectraNet considered the allowance to be a budgetary expenditure 'allowance' which may lead to higher expenditures than necessary.[338] It questioned the trade-off between ElectraNet's well developed governance and spending to the allowance:[339]

> ...good commercial practice is to manage expenditure based on business conditions and business justifications using a commercially-driven governance framework. ElectraNet has such a framework. However, it does appear that this framework may have been over-ridden to an extent in the final two years of the current RCP.

EMCa provided examples to support its view, including expenditures that ElectraNet brought forward into the 2008–13 regulatory control period to ensure its actual expenditures are comparable to the AER allowances.[340] EMCa considered:[341]

338 EMCa, *ElectraNet technical review*, October 2012, p. 36, paragraph 85.
339 EMCa, *ElectraNet technical review*, October 2012, p. 36, paragraph 86.
340 EMCa, *ElectraNet technical review*, October 2012, pp. 36–37, paragraph 86.
341 EMCa, *ElectraNet technical review*, October 2012, p. 37, paragraph 87.

> ...if ElectraNet had fully complied with its capital governance framework in the final two years of the current RCP, then it would have incurred a somewhat lower capex than it is currently forecasting for the current RCP, and materially lower than was accepted by the AER in its previous decisions.

It is evident ElectraNet is able to make prudent and efficient management decisions but at times appears to override this ability by engaging in a mindset that is focussed on spending up to the allowance set by the AER.

The AER sets allowances that TNSPs manage to operate their network prudently and efficiently over a regulatory control period. It does not set an allowance for individual projects (although it considers them when determining an allowance), but rather on the probability of these projects being undertaken. The TNSP thus has flexibility to make alternative expenditure decisions if needed to deal with operational circumstances. This allows a TNSP to make project changes which could lead to overall compositional changes.

The South Australian Council of Social Service (SACOSS) expressed concerns about ElectraNet's forecast capex proposal.[342] It noted that although ElectraNet's forecast capex was relatively consistent with capex to be incurred in the 2008–13 regulatory control period the composition was very different. Specifically, SACOSS noted it:[343]

> ...finds it hard to believe that the headline budget figures between the periods can be so close yet the compositions so different. It appears, superficially at least, that the process started from a position of maintaining the Capex budget and then justifying inclusions after that.

Figure 4.3 and Table 4.5 demonstrate this change in composition over the two regulatory control periods although the total capex levels remain relatively constant. Augmentation capex is estimated to be the largest capex category over the 2008–13 regulatory control period then it drops off significantly in the forecast. Instead replacement and refurbishment capex are the key categories of capex for the 2013–18 regulatory control period.

342 SACOSS, *Submission to the Australian Energy Regulator consultation on ElectraNet's 2013-18 transmission network revenue proposal*, August 2012, p. 4.

343 SACOSS, *Submission to the Australian Energy Regulator consultation on ElectraNet's 2013-18 transmission network revenue proposal*, August 2012, p. 4.

Figure 4.3 ElectraNet's actual and forecast capex by category ($ million, 2012–13)

Source: AER analysis, ElectraNet, *Revenue proposal*, pp. 73–74.

Table 4.5 ElectraNet's actual and forecast capex by category ($ million, 2012–13)

Capex category	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18
Augmentation	15.9	45.9	169.3	74.3	56.4	41.9	35.1	20.8	14.2	5.9
Connection	13.2	22.5	30.2	24.4	35.6	51.8	21.2	34.2	20.4	5.6
Replacement	61.5	37.8	20.1	48.5	69.5	84.8	81.5	81.3	98.6	51.8
Refurbishment	0.0	0.0	0.0	0.0	0.0	1.2	6.3	29.8	14.8	2.1
Strategic land /easements	1.3	0.2	1.2	12.6	14.5	11.9	15.3	10.3	12.2	16.1
Security /compliance	4.1	8.7	11.5	14.5	23.8	10.0	10.8	16.8	11.6	8.1
Inventory/spares	4.3	2.6	2.3	2.5	4.1	4.7	3.8	4.8	3.0	2.1
Total network	**100.3**	**117.8**	**234.6**	**176.8**	**204.0**	**206.3**	**174.0**	**197.9**	**174.9**	**91.8**
Business IT	7.1	6.3	7.6	7.9	12.7	8.9	10.7	11.4	7.2	5.5
Building/facilities	1.0	3.1	0.8	1.2	1.9	0.7	1.4	2.1	0.6	0.6
Total non–network	**8.1**	**9.3**	**8.4**	**9.1**	**14.6**	**9.6**	**12.2**	**13.5**	**7.9**	**6.1**
Total capex	**108.4**	**127.1**	**243.0**	**186.0**	**218.7**	**215.9**	**186.2**	**211.4**	**182.7**	**97.9**
Total regulatory control period					**883.1**					**894.1**

Source: ElectraNet, *Revenue proposal*, p. 76.

Based on ElectraNet's past capex performance, the AER considers ElectraNet's capex proposal is overly cautious and does not fully factor in its existing asset management methodologies and governance framework that drive prudent and efficient expenditure forecasts. In simple terms, ElectraNet underestimated how efficiently it can run its network.

Integrated asset management framework

The AER's consideration of ElectraNet's integrated asset management framework is set out in the forecast expenditure attachment 3.

Project management methodologies and cost estimation

The AER assessed ElectraNet's project management methodologies (PMM) and cost estimation processes that support the framework. Both the AER and EMCa conclude that the application of the PMM is appropriate for an asset management business such as ElectraNet.[344] Also ElectraNet's cost estimation process using the SAP database and US Cost Success Enterprise system appear to be comprehensive and likely to produce reliable and accurate cost estimates.[345]

However, the AER considers ElectraNet did not completely take into consideration the impact that the PMM and cost estimation processes will have on its forecast capex over the 2013–18 regulatory control period. For example ElectraNet's proposed cost estimation risk factor is based on historical outcomes of methods and systems that were not fit for purpose.[346] ElectraNet has since updated its estimating tools and processes and therefore should be able to undertake more reliable and accurate forecasting.

Benchmarking

The AER considers that ElectraNet adopts good external and internal benchmarking practices to drive its asset management decisions.

EMCa reviewed ElectraNet's internal benchmarking practices. It noted that ElectraNet uses ITOMS and US Cost Success Enterprise User Group to undertake external benchmarking. It also noted that, applying these benchmarks, ElectraNet has established positions relating to its current performance relative to asset spend across lines and substations. EMCa also noted that ElectraNet uses Powerlink as a good industry benchmark and that this has resulted in a significant step change in ElectraNet's asset management practices. Further, ElectraNet's internal benchmarking was evident in its continuous improvement programmes and initiatives that included measurable targets.[347]

Capex efficiency factor

The AER accepts ElectraNet's proposed efficiency adjustment factor.[348] EMCa also considered ElectraNet's proposed efficiency adjustment factor to be reasonable.[349] Its review of ElectraNet's practices demonstrated the ability to increase productivity and subsequently reduce costs. On this basis, EMCa considered a 1 per cent efficiency factor to be conservative, and that the benefits could be more.

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344 EMCa, *ElectraNet technical review*, October 2012, p. 58, paragraph 163.
345 EMCa, *ElectraNet technical review*, October 2012, pp. 80–81, paragraphs 252–256.
346 Evans & Peck, *ElectraNet capital program estimating risk analysis*, May 2012, p. 5.
347 EMCa, *ElectraNet technical review*, October 2012, pp. 54–56, paragraphs 143–152.
348 ElectraNet has called this an 'efficiency saving'. Consistent with its previous decisions the AER refers to this as 'efficiency adjustment'.
349 EMCa, *ElectraNet technical review*, October 2012, pp. 82–83, paragraphs 269–272.

EMCa notes that, consistent with ElectraNet's strategies, it was evident through its review that ElectraNet has focussed on and encouraged continuous improvements.[350]

ElectraNet applied a 1 per cent efficiency adjustment factor to its forecast capex proposal.[351] The efficiency factor reflects ElectraNet's continuous improvement approach to the management of its network. It is applied as a progressive de-escalator to each capex category total on an annual basis beginning the second year of the regulatory control period until the end of the regulatory control period.[352]

The AER acknowledges ElectraNet's move to proposing capex efficiency gains. Whilst arguably conservative the AER acknowledges the difficulties associated with quantifying an alternative adjustment. The AER considers that ElectraNet should continuously monitor, quantify and internally report on its continuous improvements. This will provide valuable information for setting expenditure forecasts consistent with the NEO (long term interests of service providers and users). At the next revenue reset, the AER will review ElectraNet's ongoing improvement initiatives during the 2013–18 regulatory control period and recognise efficiency benefits on an ongoing basis.

Cost estimation risk factor

The AER accepts the application of cost estimation risk factors but does not accept ElectraNet's proposed risk factor of 4.9 per cent. The NER requires the AER to be satisfied that forecast capex is prudent and efficient, and meets a realistic expectation of the demand forecast and cost inputs.[353] The cost estimation risk factor is applied to capital projects that are still in concept stage and yet to undergo a detailed cost build-up.[354] The concept accounts for an asymmetric risk that unforseen factors will lead actual project costs to exceed initial cost estimates. For projects at the concept stage, ElectraNet applied a cost estimation risk factor of 4.9 per cent to account for this asymmetric risk. It engaged Evans & Peck to develop its cost estimation risk factor.[355]

Consistent with the discussion above, the AER considers ElectraNet was overly cautious in its proposal. The AER is of the view that ElectraNet may not have fully considered its ability to make prudent and efficient management decisions. In particular, its ongoing improvements, through the framework, in cost estimation accuracy are underestimated.

The AER is not satisfied ElectraNet's cost estimation risk factor is a realistic expectation of the cost inputs. Therefore, the AER for this draft decision has substituted:

- 0 per cent for replacement and refurbishment capex
- 2.6 per cent for augmentation and connection capex
- 2.6 per cent all other capex.

Table 4.6 demonstrates the substitution of the AER's cost estimation risk factors reduces ElectraNet's proposed forecast capex by $19.6 million ($2012–13).

350 EMCa, *ElectraNet technical review*, October 2012, pp. 53–54, paragraphs 137–142.
351 ElectraNet, *Revenue proposal*, pp. 72–73.
352 The efficiency factor begins at almost 1 per cent in the second year annually increasing to 2 per cent in the final year. Over the entire regulatory control period it averages as being 1 per cent.
353 NER, clause 6A.6.7(c).
354 ElectraNet, *Revenue proposal*, pp. 67-68.
355 Evans & Peck, *ElectraNet capital program estimating risk analysis*, May 2012.

Table 4.6 AER's draft decision on cost estimation risk factors ($ million, 2012–13)

Cost estimation risk factors	$ million
0 per cent — replacement and refurbishment capex	–16.2
2.6 per cent — augmentation and connection	–2.9
2.6 per cent — all other capex	–0.5
Total	**–19.6**

Source: AER analysis, EMCa, *ElectraNet technical review*, October 2012, pp. 81–82 and 108.

The AER considers that the development of ElectraNet's proposed cost estimation risk factor is flawed and underestimates the level of accuracy that it can forecast. Evans & Peck developed ElectraNet's cost estimation risk factor based on historical information. This analysis examined ElectraNet's out-turn costs performance of projects undertaken during the 2008–13 regulatory control period.[356] However, ElectraNet informed Evans & Peck that its estimating tools and processes over this period were 'deficient' and it has since invested in sound cost estimation tools and processes. Evans & Peck have not taken these new estimation tools and processes into account when determining the forecast cost estimation risk factor:[357]

> ElectraNet's 2008/09 to 2012/13 regulatory budgets were based on an adaption of Powerlink Queensland's "Base Planning Object" estimation process. ElectraNet has advised Evans & Peck that it is of the view that there were deficiencies in both the way this system was applied, and in the applicability of some of the BPO rates to the South Australian situation. A revised estimating process using US Cost's Success Enterprise application has been established for the 2013/14 to 2017/18 regulatory period. This in itself presents some risk to ElectraNet.
>
> Evans & Peck's charter in relation to this analysis does not include a review of the replacement estimating system.

Given ElectraNet's focus on continuous improvement, the AER considers Evans & Peck's analysis is flawed by not taking into consideration these new cost estimating systems and processes. These systems and processes are relevant to determining how accurate ElectraNet can forecast its costs. EMCa agreed, noting it 'surprising' that ElectraNet did not account for these tools and processes in proposing its cost estimation risk factor.[358] Thus, the AER does not agree with Evans & Peck that the investment into new cost estimating systems would present bigger risks to ElectraNet over the 2013–18 regulatory control period than over the 2008–13 regulatory control period. Rather it considers ElectraNet's cost estimating tools and processes would deliver more robust and accurate estimates of forecast projects than previously. Consequently, the AER considers ElectraNet's proposal is overly cautious as its ability to forecast with accuracy is more reliable than in the past.

Further, ElectraNet's proposed cost estimation risk factor is above that of its peer and comparator Powerlink. The AER's final decision for Powerlink accepted a cost estimation risk factor of 3 per cent.[359] EMCa considered ElectraNet's management practices are at least consistent with

356 Evans & Peck, *ElectraNet capital program estimating risk analysis*, May 2012, p. 3.
357 Evans & Peck, *ElectraNet capital program estimating risk analysis*, May 2012, p. 5.
358 EMCa, *ElectraNet technical review*, October 2012, p. 81, paragraph 261.
359 AER, *Final decision, Powerlink transmission determination,* April 2012, p. 137.

Powerlink's.[360] On this basis, the AER considers it is unreasonable to accept a cost estimation risk factor above Powerlink's.

In addition, the AER's 2008 transmission determination allowed for a 2.6 per cent cost estimation risk factor for the 2008–13 regulatory control period.[361] Given that ElectraNet is focusing on improving and developing its data collection and estimating processes it should be able to provide more robust and accurate forecasts over the 2013–18 regulatory control period. On this basis and given the sound systems and processes available to ElectraNet, its cost estimation risk factor should not be above that from the AER's 2008 transmission determination. The AER considers ElectraNet's proposed cost estimation risk factor is in excess of expenditure required to achieve the capex objectives.[362] Thus, the AER does not accept ElectraNet's proposal and substituted 2.6 per cent for applicable capex categories.

The AER also considers it inappropriate to apply the same cost estimation risk factor to all capex categories, given more is known about a replacement than a new development. EMCa too considered estimate certainty is greater for replacement and refurbishment capex than for new augmentation and connection capex.[363] Replacements or refurbishments occur in environments that are known, so they do not encounter the uncertainty associated with a new project. For example, the replacement of existing transformers is undertaken in a known environment and will not face the same uncertainties as construction of new transformers. Other TNSPs have this view—for example Powerlink considers 'greenfield' developments are far less certain than locations where assets have previously been constructed.[364]

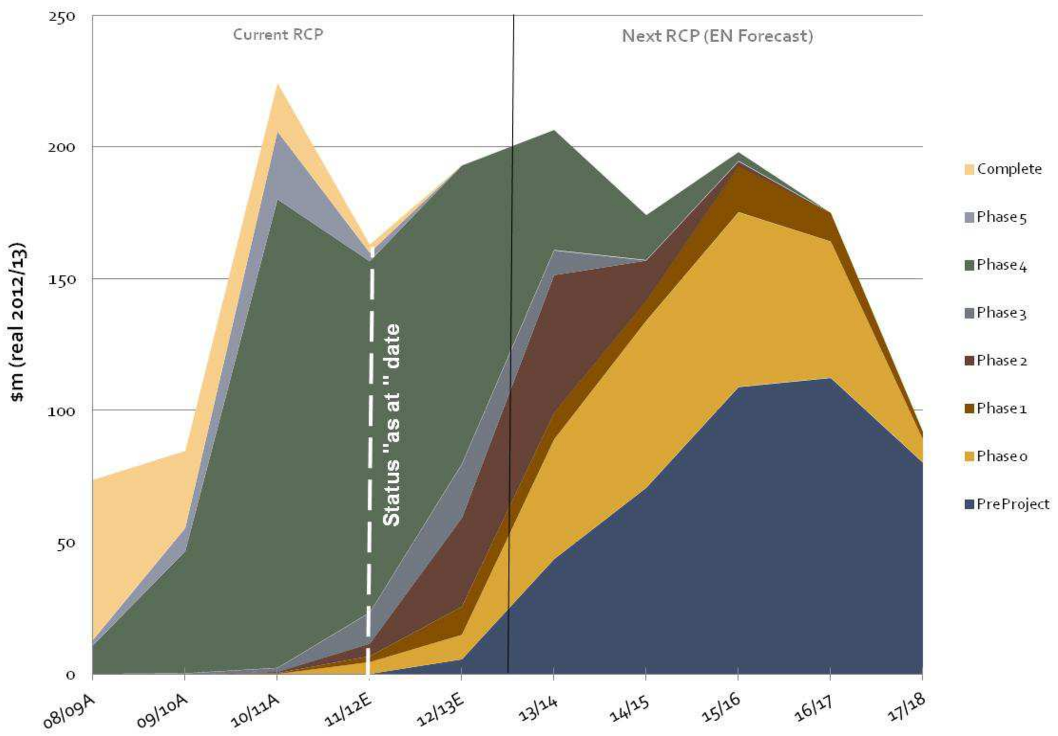
Given ElectraNet's ability to forecast with greater accuracy, and its knowledge of replacement and refurbishment capex, the AER considers the proposed cost estimation risk factor is not a realistic expectation of the demand forecast and cost inputs required.[365] The AER considers ElectraNet's proposed cost estimation risk factor is in excess of expenditure required to achieve the capex objectives.[366] Based on its expert opinion, EMCa considered that no cost estimation risk factor should be applied to ElectraNet's forecast replacement capex.[367] For these reasons, the AER does not accept ElectraNet's proposal, and it substituted 0 per cent for replacement and refurbishment capex.

Prudency adjustments

The AER considers a $31.7 million ($2012–13) reduction should be applied to ElectraNet's proposed capex due to prudency adjustments. This adjustment is in addition to the adjustments made in the forecast expenditure attachment (see attachment 3). Consistent with the discussion above, the AER considers ElectraNet was overly cautious in its proposal. ElectraNet did not fully consider its ability to make prudent and efficient management decisions. In particular, its focus on continuous improvements and the benefits of its PMM are underestimated. The AER therefore considers ElectraNet's proposed replacement and refurbishment capex is in excess of expenditure required to achieve the capex objectives, particularly for maintaining reliability, safety and security of the transmission system.[368]

360 EMCa, *ElectraNet technical review*, October 2012, p. 82, paragraph 264.
361 AER, *Final decision: ElectraNet transmission determination*, 11 April 2008, p. 52.
362 NER, clauses 6A.6.7(a)(3) and (4).
363 EMCa, *ElectraNet technical review*, October 2012, p. 82, paragraph 266.
364 EMCa, *ElectraNet technical review*, October 2012, p. 82, paragraph 266.
365 NER, clause 6A.6.7(c).
366 NER, clause 6A.6.7(a)(3) and (4).
367 EMCa, *ElectraNet technical review*, October 2012, p. 82, paragraph 267 and Annexure D, p. D–7–8, paragraphs 736–738.
368 NER, clause 6A.6.7(a)(4).

Figure 4.4 ElectraNet capex by PMM phase ($ million, 2012–13)



Source: EMCa, *ElectraNet technical review*, October 2012, p. 58, figure 17.

Figure 4.4 shows ElectraNet's capex by PMM phase. The AER notes ElectraNet's forecast capex contains a significant proportion of projects that are still in the early stages of development. As a result, detailed cost scoping for these projects is yet to be developed. ElectraNet's projects are subject to the PMM. The PMM has six progression phases, ranging from the concept stage (Phase 0—Initiate project) to complete project scoping (Phase 5—Finalise project). At the end of each phase, a formal gate review is undertaken, when the project must obtain approval to proceed to the next phase. During each phase, prudent decision making is undertaken, including alternative options and delivery options, which may result in more efficient outcomes. The AER considers there is a high probability that efficiencies will be identified given ElectraNet's sound cost estimation process. EMCa agreed:[369]

> ...we consider that gains will be possible through the application of prudent decision making at various points of a projects life cycle.

However, the AER considers ElectraNet has been overly cautious in its proposal as some of these efficiencies are quantifiable now and therefore should be accounted for in a capex forecast that reasonably reflects the capex criteria.[370] The AER considers even more efficiencies are likely to be realised by ElectraNet as these projects proceed through the PMM phases over the 2013-18 regulatory control period. The AER considers there is evidence of this scoping in its observations of ElectraNet's past capex.

EMCa reviewed a representative sample of projects. The sample included eight of ElectraNet's proposed replacement projects (47 per cent of the total replacement capex in value) and EMCa was

369 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraph 339.
370 NER, clause 6A.6.7(c).

able to quantify $11.5 million ($2012–13) of potential prudency gains.[371] For example EMCa noted that several concept phase substation replacement projects included large increases in transformer capacity. EMCa considered ElectraNet had the ability to undertake prudent measures such as altering the power factor at these connection points to allow the deferral of these projects and thereby produce more efficient options.[372] Such measures would not compromise ElectraNet's ability to maintain a reliable, safe and secure transmission system.[373]

The $11.5 million ($2012–13) of potential prudency gains represents 7 per cent of the total capex of the replacement projects reviewed. EMCa concluded that its sample review is statistically representative and this level of efficiency and prudency gain should be achievable across all of ElectraNet's proposed replacement and refurbishment capex.[374] EMCa considered this is consistent with its findings on ElectraNet's management of its capex over the 2008–13 regulatory control period.[375]

The AER agrees with EMCa and considers a $31.7 million ($2012–13) reduction should be applied to ElectraNet's proposed replacement and refurbishment capex. The AER considers ElectraNet's forecast replacement and refurbishment capex is in excess of the expenditure to form part of a total capex that will enable ElectraNet to achieve the capex objectives. Thus the AER considers this adjustment allows for a forecast that reasonably reflects the capex criteria.[376]

SA Water replacement assets

The AER agrees with ElectraNet that due to their age and condition, assets (primarily substations) relating to SA Water pumping stations require replacement. The cost of these replacements is $123.4 million ($2012–13).

The AER notes that due to grandfathering arrangements in the NER it has limited scope to make adjustments to ElectraNet's proposal.[377] Therefore, the AER accepts ElectraNet's proposed replacement for these assets.

SA Water’s connection services are provided by ElectraNet’s existing assets and are deemed to be prescribed connection services under the NER. Typically, under chapter 6A of the NER, connection services are negotiated services and are paid for by the connecting customer. For example, if SA Water were to build a new pumping station at a new location, this connection service would be a negotiated service.

Clause 11.6.11 of the NER establishes that a defined group of assets will be considered to be prescribed transmission services under a grandfathering arrangement as long as a number of factors are satisfied. One key factor is that the replacement asset must provide the same service as is currently provided. Should the service levels change, at a Transmission Network Users request, then the grandfathering arrangements would cease to apply to that replacement asset. Consequently, that connection asset would provide a negotiated service and expenditure associated with providing negotiated services could not be included in ElectraNet’s revenue proposal.

371 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraphs 340–344 and 702–704.
372 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraph 343 and Annexure B, pp. B–3–5, paragraphs 676–689.
373 NER, clause 6A.6.7(a)(4).
374 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraphs 340–344.
375 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraph 345.
376 NER, clause 6A.6.7(c).
377 NER, clause 11.6.11.

The AER notes ElectraNet's proposed replacement capex for assets relating to SA Water pumping stations maintains the service level and will not occur at SA Water's request. Therefore, the assets continue to be classified as prescribed transmission services.

The AER notes that SA Water would incur an increase in its charges if the services ElectraNet provides to it become negotiated services. The AER considers the clause as drafted has the potential to lead to inefficient replacement decisions as users such as SA Water will be reluctant to request increased or different functionality. The AER recommends that clause 11.6.11 be reviewed.

EMCa reviewed the replacement of these assets and is concerned that there is a lack of justification for the large expenditure proposed for the like–for–like replacement over the 2013–18 regulatory control period.[378] EMCa concluded that strategic planning between affected water and electricity stakeholders could provide a more optimised approach to the replacement of these assets. Based on its review, it could not conclude that the proposed replacement expenditure represented efficient costs.[379] EMCa further stated:[380]

> If regulatory arrangements present barriers to this approach being taken, considerations should be given to changing them.

The South Australian Minister for Mineral Resources and Energy also noted concerns regarding the impact of electricity prices borne by the classification of services:[381]

> In the current climate of increasing electricity prices, in making its assessment, the AER must ensure all the expenditure is fully justified while being mindful of the financial impact its decision will have on South Australian consumers. It is important that the AER scrutinise projects identified as negotiated services which should be funded by the proponents rather than the costs being levelled across all consumers.

In the context of its consultative approach to investigating issues, the AER invited EMCa, ElectraNet and SA Water to a discussion facilitated by the AER.[382] Having considered the details set out in the AER letter and in the context of its previous discussions with ElectraNet, SA Water was content to respond in writing. SA Water stated:[383]

> ...SA Water is satisfied with the existing level of service provided by ElectraNet and anticipates the service will continue for the foreseeable future. SA Water has not requested any changes to the existing service levels provided by ElectraNet at the connection points in question. It assumes ElectraNet will carry out competent asset management planning across the installed assets to ensure that the service is provided reliably over time. Clearly, ElectraNet is carrying out asset management and has proposed asset renewals. It is for the service provider and pricing regulator to agree on the details. SA Water, as customer, simply requires assurance that service level risks are managed effectively over time at lowest whole of life cost.

In relation to the grandfathering arrangements in the NER, SA Water stated:[384]

> Your letter also refers to the matter of service connection conditions (negotiated services versus grandfathered prescribed services). As stated above SA Water has not requested any change in service levels in relation to the proposed capital projects, notes you have the same understanding, and assumes that current service conditions will be unaffected.

378 EMCa, *ElectraNet technical review*, October 2012, pp. 95–96, paragraph 332.
379 EMCa, *ElectraNet technical review*, October 2012, p. 96, paragraph 337.
380 EMCa, *ElectraNet technical review*, October 2012, p. 93, paragraph 335.
381 Hon Tom Koutsantonis MP (Minister for Mineral Resources and Energy), *Letter to the AER*, 27th September 2012.
382 AER, Letter to SA Water, *ElectraNet revenue reset 2013—replacement of substations providing services to SA Water pumping stations*, 28 September 2012.
383 Peter Seltsikas (SA Water), *Letter to the AER: ElectraNet revenue reset 2013—replacement of substations providing services to SA Water pumping stations*, 12 October 2012.
384 Peter Seltsikas (SA Water), *Letter to the AER: ElectraNet revenue reset 2013—replacement of substations providing services to SA Water pumping stations*, 12 October 2012.

Thus, the AER has no scope to make adjustments to ElectraNet's proposal. The AER therefore accepts ElectraNet's proposed replacement capex relating to SA Water pumping station assets. However, the AER notes that clause 11.6.11 appears to prevent an incentive to promote prudent and efficient replacement capex decisions.

Capex / opex trade-off

See forecast expenditure attachment 3.

Real cost escalators

Overall, the AER does not accept that ElectraNet's proposed real cost escalators reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.[385] The AER considers ElectraNet's proposed real cost escalators are in excess of expenditure required to achieve the capex objectives.[386] However there are parts that the AER does accept. It has determined the substitute escalators which reflect the AER's considerations that:

- labour cost forecasts developed by Deloitte Access Economics (DAE) reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives
- exchange rates and forecast inputs for material and land value escalation should be updated to reflect most recent data
- applying land type escalators to corresponding land and easement projects reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.

Attachment 1 contains the AER's consideration of the real cost escalators proposed by ElectraNet. The impact of the application of the AER's real cost escalators on ElectraNet's proposed capex is shown in Table 4.7.

Table 4.7 Impact of AER's draft decision real cost escalation ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2018–19	Total
ElectraNet proposal	2.9	5.9	10.6	12.5	11.0	42.9
AER draft decision	2.9	5.4	8.0	8.7	8.7	33.6
Difference	0.0	0.5	2.6	3.9	2.3	9.3

Source: AER analysis.

4.4.2 Strategic land and easement acquisitions

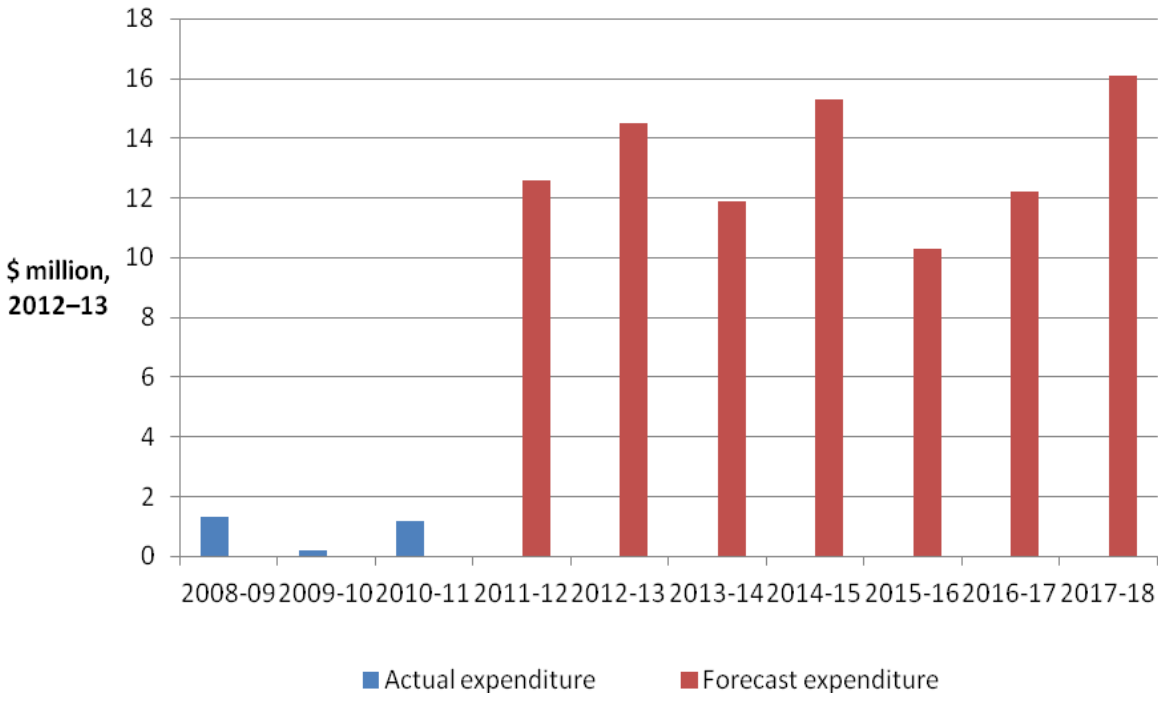
The AER does not accept ElectraNet's proposed strategic land and easement capex of $65.8 million ($2012–13). ElectraNet was overly cautious in proposing this category of its capex and therefore a substitute forecast of $13.4 million ($2012–13) was derived.[387] This conclusion was reached by assessing ElectraNet's strategic land and easement forecast against the requirements in the capex criteria.[388]

385 NER, clause 6A.6.7(c)(3).
386 NER, clauses 6A.6.7(a)(3) and (4).
387 NER, clause 6A.6.7(d).
388 NER, clause 6A.6.7(c).

Land and easements are 'strategic' if they are acquired in the 2013–18 regulatory control period but are not expected be used for the commencement of transmission projects until after the completion of that regulatory control period. The AER and ECCSA agree that strategic land and easement acquisitions can be appropriate.[389] However, to satisfy the capex criteria the proposed expenditure must reasonably reflect the efficient and prudent costs of maintaining the quality, reliability and security of supply of prescribed transmission services.[390] ElectraNet's proposed strategic land and easement capex does not reasonably reflect those requirements and therefore the AER determined a substitute forecast.[391]

Historically, ElectraNet's actual costs relating to strategic land and easement acquisitions averaged $0.8 million per regulatory year for the 2008–09, 2009–10 and 2010–11 regulatory years.[392] In the 2011–12 and 2012–13 regulatory years, these costs are forecast to increase to $12.6 million and $14.2 million respectively. Figure.4.5 shows ElectraNet's actual and forecast strategic land and easement capex.[393]

Figure.4.5 ElectraNet's actual and forecast strategic land and easement expenditure ($ million, 2012-13)



Source: ElectraNet, *Revenue proposal*, p. 76.

The AER does not accept ElectraNet's proposed strategic land and easement capex because it is not supported by a satisfactory cost–benefit analysis. This would involve assessing the risks of delaying each proposed acquisition, such as the potential for encroaching developments. These risks would then be compared with the estimated carrying costs of the strategic land acquisition. This type of cost–benefit analysis was not provided by ElectraNet. While it identified some of the risks involved with each land parcel and easement, the cost of addressing these risks were not measured. The

389 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 48.
390 NER, clauses 6A.6.7(a)(3), (c)(1) and (c)(2).
391 NER, clause 6A.6.7(d).
392 ElectraNet, *Revenue proposal,* p. 76.
393 ElectraNet, *Revenue proposal*, p. 76.

efficiency and prudency of the proposed costs have therefore not been demonstrated.[394] The AER considers that incremental purchases of ElectraNet's land and easement requirements would better reflect the capex criteria[395] and further the achievement of the national electricity objective (NEO).

ElectraNet provided a report it commissioned from the property consulting firm Connor Holmes. Using that report the AER observed 11 projects for which land or an easement is already designated for ElectraNet's use by planning instruments.[396] Planning instruments include the 30 Year Greater Adelaide Plan (30 Year Plan) and council designations. The 30 Year Plan operates at the state Government level and has a statutory effect requiring regional development plans to be consistent with its land use policies.[397] Council designations operate at the regional level and provide reasonable expectations that competing land users will not encroach on the designated land area. Given these protections, the AER considers ElectraNet's proposal is overly cautious as it is not clear that it would be efficient for all 11 land parcels and easements to be acquired. Table 4.8 summarises the AER's findings.

394 NER, clauses 6A.6.7(a)(3), (c)(1) and (c)(2).
395 NER, clause 6A.6.7(c).
396 Connor Holmes, *Review of Strategic Plan Acquisition Program*, May 2012.
397 South Australian Government*, 30 Year Greater Adelaide Plan*, 2010 p. 25 (accessed at: http://www.dplg.sa.gov.au/plan4adelaide/index.cfm).

Table 4.8 Land and easements protected by planning instruments

Project	Risk	AER's assessment
Eyre Peninsula Reinforcement land and easement acquisition	Transmission corridor should be obtained early to ensure an extensive number of planned and mooted competing land uses d	The project area is identified in the Eyre and Western Region Plan
Fleurieu Peninsula Reinforcement land and easement acquisition	Visually sensitive area close to several small settlements	Identified in the 30 Year Plan
Riverland Reinforcement land and easement expansion	Potential community opposition in the Berri Barmera region	The proposed route is identified in the Murray and Mallee Region Plan
Mount Barker South triple circuit	To guarantee tenure, the easement should be acquired.	Land currently set aside in the Alexandria Council Development Plan
Torrens Island	Environmental concerns relating to mangroves, the Barker Inlet and a dolphin sanctuary	Project area currently zoned as Public Space (Power Station)
Morphett Vale East/Cherry Gardens/Happy Valley easement expansion	Without early acquisition, a high risk that a suitably wide easement corridor would not be available	Identified in the 30 Year Plan Communication with the city of Onkaparinga determined there are no known development plans or proposals to intensify development within the project area.
Para to Tungkillo easement expansion	Possibility of Environmental Protection and Biodiversity Act referrals and extensive community consultation, which may result in long lead times	Identified in the 30 Year Plan Communication with the Adelaide Hills Council and the City of Playford determined there are no known development plans or proposals to intensify development within the project area.
South East to Mount Gambier to Snuggery easement expansion	The project covers a significant distances including several kilometres of easement through urban and semi urban areas surrounding Mount Gambier	Identified in the Limestone Coast Region Plan
Mallala to Para easement expansion	To guarantee tenure, the easement should be acquired.	Identified in the 30 Year Plan
Templers to Para easement expansion	Project area is considered to be highly sensitive, with urbanisation and competing land uses.	Identified in the 30 Year Plan
Mallala to Templers West land and easement acquisition	Risks associated with greenfield development in reasonable proximity to existing settlements	Identified in the 30 Year Plan, with project notated 'future redbanks-templers 275 kV transmission line'

Source: Connor Holmes, *Review of Strategic Plan Acquisition Program*, May 2012.

The AER identified an additional 10 acquisitions proposed by ElectraNet that are not subject to planning instruments but traverse regional areas removed from urban locations and townships. Connor Holmes observed that the remoteness of these acquisitions gives rise to low risks of other land users encroaching on ElectraNet's potential easements. As such, it is unclear from the information provided why a prudent TNSP seeking to minimise its costs would need to acquire these land parcels and easements before they are required to meet the expected demand for prescribed transmission services. The AER considers to do so is an overly cautious approach. The AER's analysis of these 10 proposed acquisitions is contained in Table 4.9.

Table 4.9 Land and easements at low risk of becoming unavailable

Project	Risk	AER's assessment
Yorke Peninsula	Potential for new wind farm	Communication with the Wakefield Regional Council has determined there are no known development plans or proposals to intensify development within the project area.
Kadina East to Hummocks land and easement acquisition	Project area in the periphery of townships with some land owners owning speculative holdings with a vision of potential rezoning	Communication with Copper Coast and Barunga West Council determined there are no known development plans or proposals to intensify development within the project area.
Cultana to Stony Point	Easement should be obtained early to ensure competing land uses do not inhibit the proposed transmission corridor.	The competing land uses involve energy intensive industries—for example, a planned desalinisation plant—which have an incentive to accommodate a proposed transmission corridor.
Snuggery substation	Suitable land for the construction of a new substation is limited and should be acquired early.	Communication with Wattle Range Council determined there are no known development plans or proposals to intensify development within the project area.
Tepko substation land acquisition	The project area is within a visually sensitive area in which community opposition can be anticipated.	Communication with the City of Mid Murray Council determined there are no known development plans or proposals to intensify development within the project area.
Wilmington substation land acquisition	Development pressures from wind farms and rural living allotments may give rise to landowner sensitivity in the project area.	The project area is primarily within rural/farming land.
Lincoln Gap land acquisition	Other competing land uses relating to wind farms and potentially mining mean there is potential for increased conflicts if land is not acquired promptly.	The project area is primarily on rural land that extends between Port Augusta and Whyalla.
Fourth northern suburbs substation land acquisition	The proposed site is located near Edinburgh RAAF base, where development controls apply for certain vertical structures that may impact on airport operations.	Communication with the City of Playford determined there are no known development plans or proposals to intensify development within the project area.
Jamestown substation land acquisition	History of community opposition to wind farms could give rise to sensitivities associated with	Communication with Northern Areas Council determined that there are no strategic plans for growth.

	infrastructure delivery.	
Angas Creek Substation Augmentation Land Acquisition	The project area is within a visually sensitive hills area whereby community opposition can be anticipated.	These settlements are unlikely to expand based on 30 Year Plan directions.

Source: Connor Holmes, *Review of Strategic Plan Acquisition Program*, May 2012.

Connor Holmes recommended that all 21 of the proposed acquisitions should be made in the 2013–18 regulatory control period. ElectraNet appears to have accepted this advice and implemented an approach that considers purchasing land and easements to be the only strategic option. EMCa concluded that this is not prudent or efficient.[398] Rather, all other regulatory and legislative options should be pursued before the expense of making a strategic acquisition can be justified. ElectraNet has done this to some extent by obtaining planning instruments on 11 occasions. However, it has not given sufficient weight to the protections that they afford and proposed an overly cautious land and easement capex.

ElectraNet cites amendments to the Electricity Transmission Code (ETC) as driving an increase in its strategic land and easement capex.[399] The AER considers that ElectraNet has overstated the obligations under the ETC. From 1 July 2013 an amended ETC takes effect which will require ElectraNet to use its 'best endeavours' to acquire all necessary land and easements within three years of a change in forecast agreed maximum demand (FAMD) at a connection point.[400] This three year lead time does not justify ElectraNet's proposed capex which includes expenditure for 14 land parcels and easements that are not required to meet demand for prescribed transmission services until at least the 2023–28 regulatory control period.

The AER does not consider ElectraNet to have substantiated its proposed strategic acquisitions. However, it is likely that some level of strategic purchases can be justified in the upcoming regulatory control period. The AER has therefore accepted $13.4 million ($2012–13) as an indicative substitute forecast. The AER considers this to be sufficient for ElectraNet to incrementally acquire its land and easements requirements. The AER may review the appropriate quantum prior to making its final decision.

4.4.3 Load driven capex

The AER does not accept ElectraNet's proposed load driven capex as it does not reasonably reflect a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives, particularly to meet the expected demand.[401] In addition to ElectraNet being overly cautious in parts of its capex proposal, the AER considers ElectraNet's demand forecast has been overstated. As discussed in attachment 2, the AER does not accept ElectraNet's demand forecast and has substituted an alternative demand forecast supplied by EMCa.

The AER's alternative demand forecast is overall approximately 14 per cent lower than ElectraNet's forecast for the 2013–18 regulatory control period. Subsequently, the AER considers a reduction of $103.7 million ($2012–13) to ElectraNet's forecast demand driven capex is required to account for the lower demand forecast. This equates to the following adjustments:

- augmentation capex reduced by $17.6 million ($2012-13)

398 EMCa, *ElectraNet technical review*, October 2012, paragraph 368.
399 ElectraNet, *Email response to information request EMCa/039, Strategic Land Acquisition Policy*, 5 July 2012, p. 6.
400 Electricity Transmission Code, TC/07, clause 10.1.
401 NER, clauses 6A.6.7(c)(3) and 6A.6.7(a)(1).

- connection capex reduced by $29.6 million ($2012–13)
- replacement capex reduced by $56.5 million ($2012-13).

The AER requested ElectraNet provide a connection point forecast consistent with AEMO's 2012 demand forecast, and to advise the augmentation and connection capex that would be consistent with this forecast. The EUAA and ECCSA considered the AER should require ElectraNet to consider the downward forecast of peak demand in AEMO's forecast.[402] ElectraNet declined to provide this information.[403] The AER subsequently requested the corresponding reduction in forecast capex if the demand forecast at each connection point were to change by the same proportion as AEMO's 2012 forecast. Again, ElectraNet did not provide this information. However, ElectraNet did provide the reduction in capex that corresponded to the low demand growth scenario undiversified connection point peak demand forecasts provided by SA Power Networks (formerly ETSA Utilities) and direct-connect customers.[404]

Since ElectraNet declined to provide the requested information, the AER's ability to determine an appropriate substitute capex forecast is compromised. EMCa developed a methodology to produce a forecast of augmentation and connection capex using the alternative demand forecast, as follows:

- EMCa reviewed the list of proposed augmentation and connection capex projects to identify load driven projects—EMCa concluded that $49 million ($2012–13) of augmentation and connection projects were not load driven and therefore should not be subject to any reduction.
- EMCa assumed that projects already commenced could not be deferred—EMCa determined that no adjustment could be made to the $28 million ($2012–13) of augmentation projects and $56 million ($2012-13) of connection projects with commissioning dates in 2013 or 2014.
- EMCa considered adjustments to forecast augmentation and connection capex could not be made on a pro rata basis. Applying the reduction on a pro rata basis would imply that almost no further load driven augmentation or connection capex would be required for the 2013–18 regulatory control period. EMCa accepted that load growth occurs unevenly and some load driven augmentation or connection capex would be required. It therefore assumed that projects not already commenced could be deferred on average by three years.[405]

EMCa concluded reductions should be made to ElectraNet's forecast augmentation and connection capex. The AER's application of EMCa's method reduced ElectraNet's augmentation and connection capex by $17.6 million ($2012–13) and $29.6 million ($2012–13) respectively.

EUAA raised concerns regarding ElectraNet's claim about the amount of forecast augmentation and connection capex not being driven by demand growth.[406] The AER acknowledges EUAA's concerns but considers its analysis confirms ElectraNet's proposal is accurate.[407] Thus the AER accepts that a considerable amount of ElectraNet's forecast augmentation and connection capex is not driven by demand growth. ElectraNet stated that the augmentation projects are centred on substation related works driven by reliability requirements, reactive plant projects enabling deferral of major augmentation, and expansion of telecommunication capacity to meet growing bandwidth

402 EUAA, *Submission to ElectraNet's revenue proposal for 2013–18*, August 2012, pp. 7–9; ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 13.
403 ElectraNet, *Response to AER RP 003, demand forecasts*, ENET082, 21 June 2012, [public version].
404 ElectraNet, *Email response to information request AER RP 16: CAPEX impact of AEMO's 2012 demand forecast ENET238*, August 2012 [Public version].
405 EMCa, *ElectraNet technical review*, October 2012, pp. 92–3, paragraphs 317–322.
406 EUAA, *Submission to ElectraNet's revenue proposal for 2013–18*, August 2012, p. 11.
407 EMCa, *ElectraNet technical review*, October 2012, Annexure D, p. D–3–4, paragraph 717.

requirements.[408] Further, connection projects are required to increase the capacity of existing distribution connections, including substation upgrades required under the ETC at Baroota and Dalrymple, and the establishment of a new distribution connection point requested by SA Power Networks at Munno Para.[409]

ElectraNet stated: [410]

> A notable feature of the transmission network capital expenditure forecast for 2013-14 to 2017-18 is that the augmentation and distribution connection point projects identified are largely independent of the generation development and demand forecast assumptions considered in the various scenarios modelled.

The AER considers EMCa's method is appropriate because it only takes into account load driven affected augmentation and connection capex over the 2013–18 regulatory control period.

In addition, ElectraNet advised the AER that a lower demand growth scenario would also impact its forecast replacement capex as it would allow several replacement projects to be deferred.[411] EMCa applied the same methodology to ElectraNet's forecast replacement capex. Accordingly, EMCa recommended a reduction to replacement capex which is impacted by the application of the AER's substitute demand forecast. Therefore, the AER agrees with EMCa's conclusions and consequently made a reduction of $56.5 million ($2012–13) to ElectraNet's proposed replacement capex.

4.4.4 Equity raising costs

The AER accepts ElectraNet’s proposed method for determining its benchmark equity raising costs allowance associated with its forecast capex. This method is consistent with that used by the AER in its recent final decision for Powerlink's electricity transmission network. The AER considers that this method represents the approach that a prudent service provider acting efficiently would apply in raising equity, given its particular capital raising requirements. This is because the method:

- assumes that service providers first use the cheapest sources of equity
- takes account of all the likely sources of equity
- takes account of the requirements of a prudent service provider acting efficiently, by using the inputs and outputs of the PTRM as found by the AER to be efficient.

The AER, however, has updated ElectraNet's proposed equity raising cost allowance to reflect the draft decision RAB roll forward and indicative WACC determined by the AER. The AER’s draft decision, therefore, is to provide an allowance for equity raising costs of $0.2 million ($2012–13). The derivation of ElectraNet's equity raising costs allowance is shown in Table 4.10 and Table 4.11. The AER will update ElectraNet's proposed equity raising cost allowance for its final decision.

408 ElectraNet, *Revenue proposal*, p. 74.
409 ElectraNet, *Revenue proposal*, p. 74.
410 ElectraNet, *Revenue proposal*, pp. 75–76.
411 ElectraNet, *Email response to information request AER RP 16: CAPEX impact of AEMO’s 2012 demand forecast ENET238*, August 2012, pp. 2–3 [Public version].

Table 4.10 AER's draft decision cash flow analysis for ElectraNet's benchmark equity raising costs ($ million, nominal)

Cash flow analysis	Total	Notes
Dividends	179.1	Set to distribute imputation credits assumed in the PTRM (100 per cent).
Dividends reinvested	53.7	Availability of reinvested dividends, capped at 30% dividends paid.
Capex funding requirement	686.0	Forecast capex funding requirement (including half year WACC adjustment).
Debt component	289.1	Set to equal 60% of annual change in RAB.
Equity component	396.8	Residual of capex funding requirement and debt component.
Retained cash flow available for reinvestment	372.9	Exclude dividends reinvested.
Equity required	23.9	Equals equity component less retained cash flows.

Source: AER analysis.

Table 4.11 AER's draft decision cash flow analysis for ElectraNet's benchmark equity raising costs ($ million, 2012–13)

Cash flow analysis	Total	Notes
Equity component	369.6	Residual of capex funding requirement and debt component.
Retained cash flow available for reinvestment	345.5	Exclude dividends reinvested.
Equity required	24.1	Equals equity component less retained cash flows.
Dividends reinvested	49.8	Availability of reinvested dividends, capped at 30% dividends paid.
Dividend reinvestment plan required	24.1	Required reinvested dividends.
Seasoned equity offerings required	0.0	Required season equity offerings (SEOs).
Cost of dividend investment plan	0.2	Required reinvested dividends multiplied by benchmark cost (1%).
Cost of season equity offerings	0.0	Required SEOs multiplied by benchmark cost (3%).
Total equity raising costs	0.2	Total costs of dividend reinvestment plan and SEOs. To be added to RAB at the start of the regulatory control period.

Source: AER analysis.

4.4.5 Components of ElectraNet's capex proposal that the AER accepts

The AER accepts the categories of ElectraNet's forecast capex in Table 4.12 reasonably reflect the efficient and prudent costs of a TNSP. Table 4.12 sets out the categories and accepted values.

Table 4.12 Components of ElectraNet's capex proposal that the AER accepts ($ million, 2012–13)

Project category	Sub-category	$ million, 2012–13
NETWORK		
Non-load driven	Security/compliance	56.9
	Inventory/spares	18.0
NON-NETWORK		
	Business IT	43.7
	Buildings/facilities	5.6

Source: AER analysis, ElectraNet, *Revenue proposal*, pp. 73–74. Numbers may not be the same as ElectraNet's proposal due to the AER's draft decision on cost estimation risk factors and real cost escalation.

The AER's review of these capex categories established ElectraNet's forecasts are reasonable. The proposed expenditures are largely consistent with those incurred by ElectraNet in the 2008–13 regulatory control period.[412] The ECCSA agreed the forecast of these capex categories are reasonable and consistent with expenditure incurred in the 2008–13 regulatory control period.[413]

- security/compliance—down $5.3 million ($2012–13)
- inventory spares—up $2.6 million ($2012–13)
- business IT—up $2.1 million ($2012–13)
- buildings/facilities—down $2.3 million ($2012–13).

EMCa's considered these forecasts were consistent with the application of ElectraNet's asset management framework and found no reasons to consider these expenditures to be unreasonable.[414]

4.5 Revisions

Revisions 4.1: make all necessary amendments to reflect the AER’s draft decision on conforming capital expenditure for the 2013–18 regulatory control period in Table 4.1 and Table 4.2.

412 NER, clause 6A.6.7(e)(5).
413 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 44.
414 EMCa, *ElectraNet technical review*, October 2012, p. 105, paragraph 386.

5 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital costs incurred in the provision of prescribed transmission services. It includes labour costs and other non-capital costs.

The Australian Energy Regulator (AER) must accept ElectraNet's proposed forecast opex for the 2013–18 regulatory control period, if satisfied the forecast reasonably reflects the opex criteria set out in the National Electricity Rules (NER).[415] If not satisfied, the AER must give reasons for not accepting the proposal and estimate the total required opex that reasonably reflects the opex criteria. In doing so, it must have regard to the opex factors.[416]

5.1 Draft decision

The AER does not accept ElectraNet's proposed total opex of $478.1 million ($2012-13 mid-year)[417] for the 2013–18 regulatory control period because it does not meet the opex criteria.[418] It examined ElectraNet's proposal using two approaches: a top down approach (section 5.4.2) and a detailed bottom up technical review (section 5.4.3). Both reviews showed ElectraNet's forecast opex for the 2013–18 regulatory control period does not meet the opex criteria.[419]

The AER substituted its total opex forecast developed from a top down approach, but with step changes included to reflect ElectraNet's changing business environment. Its substitute forecast opex for the 2013–18 regulatory control period is $397.6 million, which is $80.5 million less than ElectraNet's proposal but still a 17 per cent (real) increase on the 2008–13 total opex allowance.

Table 5.1 and Figure 5.1 compare the AER's draft decision for total opex with ElectraNet's opex proposal. Table 5.2 shows the opex draft decision by cost driver and by year.

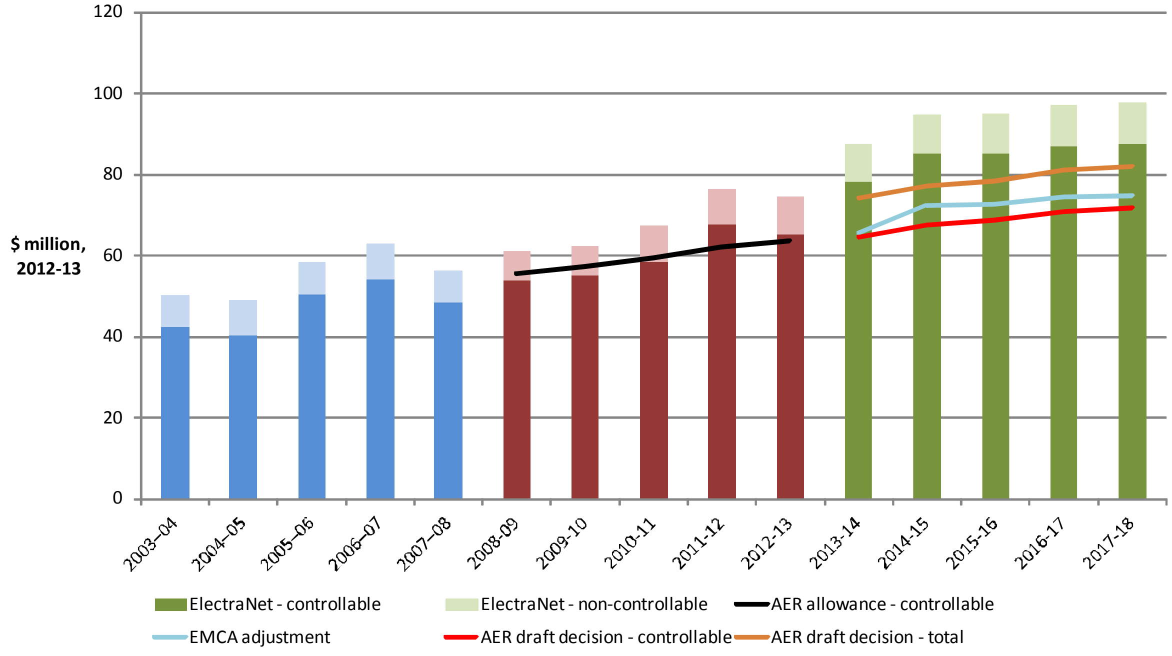
Table 5.1 ElectraNet proposed and approved total opex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	88.8	95.8	96.2	98.3	99.0	478.1
AER draft decision	75.0	78.3	79.3	82.0	83.1	397.6
Difference	–13.8	–17.5	–16.9	–16.3	–15.9	–80.5

Source: AER analysis.

415 NER, clause 6A.6.6 (c).
416 NER, clauses 6A.6.6 (d), 6A.12.1(c) and 6A.14.1(3)(ii).
417 Unless otherwise stated, all dollar amounts are expressed in 2012–13 dollars in this attachment and are in mid year terms. Because all post tax revenue model inputs are in end-of-year terms, these amounts are escalated by a half year of inflation before being entered in the post tax revenue model.
418 NER, clause 6A.6.6(c).
419 NER, clause 6A.6.6(c).

Figure 5.1 **Comparison of ElectraNet's historical and forecast opex, and the AER's draft decision ($ million, 2012–13)**



Source: AER analysis based on ElectraNet, *Revenue proposal* and ENET100.

Table 5.2 **AER's draft decision on ElectarNet's forecast total opex allowance ($ million, 2012-13)**

Category	2013–14	2014–15	2015–16	2016–17	2017–18	Total	Proposed
Controllable							
Routine maintenance	15.0	16.1	16.4	16.6	16.8	80.9	80.9
Corrective maintenance	8.1	8.7	8.8	9.0	9.1	43.7	68.8
Operational refurbishment	8.8	9.4	9.5	9.6	9.7	47.0	64.9
Network operations*	7.7	8.0	8.1	8.2	8.3	40.2	47.3
Network optimisation	0.0	0.0	0.0	0.0	0.0	0.0	13.3
Maintenance support*	9.2	9.5	9.7	9.9	10.2	48.6	69.9
Asset manager support*	9.4	9.7	9.8	11.4	11.5	51.7	43.8
Corporate support*	6.2	6.3	6.3	6.3	6.3	31.4	33.8
Total controllable	**64.5**	**67.6**	**68.6**	**70.9**	**71.9**	**343.5**	**422.8**
Non-controllable							
Self-insurance	1.3	1.3	1.4	1.4	1.4	6.8	7.5
Network support	8.1	8.2	8.2	8.5	8.6	41.6	41.6
Debt raising	1.1	1.1	1.2	1.2	1.2	5.8	6.3
Total non-controllable	**10.5**	**10.7**	**10.8**	**11.1**	**11.2**	**54.2**	**55.4**
Total	**75.0**	**78.3**	**79.3**	**82.0**	**83.1**	**397.6**	**478.1**

Source: AER analysis. *ElectraNet changed the way it categorised its opex between the 2008–13 and 2013–18 regualtory control periods. Because the new categories are different to those used to report historic costs, the AER asked ElectraNet to provide the new cost mapping for 2010–11 (which the AER used as the base year). The AER opex forecasts are based on the new cost categories. The AER notes that the new mapping particular impacts on how costs are allocated between network operations, corporate support, maintenance support and asset manager support.

The AER assessed key factors underpinning ElectraNet's proposed total forecast opex. A key issue was that Electranet had not sufficiently factored the expected benefits of its integrated asset management framework into its opex (or capex) proposal. In particular, ElectraNet did not set out the economic benefits of deferring replacements by increasing opex. Thus the AER consider ElectraNet had been overly cautious in its proposal by not taking these into account.

The AER therefore decreased ElectraNet's capex allowance by $50.1 million, to reflect the capex/opex tradeoff benefits (section 4.1). The AER increased ElectraNet's opex allowance for the 2013–18 regulatory control period by including a step change increase to ElectraNet's routine maintenance forecast; an increase (over the revealed costs trend line) of $10 million and this reflects ElectraNet's additional ongoing opex requirements. This increase will form the basis of future revealed costs and interacts with the efficiency benefit sharing scheme (EBSS) discussed in attachment 12.

The AER engaged Energy Market Consulting Associates (EMCa) to provide advice on ElectraNet's opex proposal. EMCa provided a forecast for the 2013–18 regulatory control period based on its bottom-up analysis and review of the proposal. The AER's substitute forecast is founded on a top down revealed costs methodology (also called historical costs approach). The AER's assessment method principally from EMCa's, but the AER's draft decision was informed and supported by EMCa's advice and EMCa's forecast provided a robust cross check. Both the AER and EMCa's assessment methods found that ElectraNet's forecast was higher than reasonable. The reconciliation between the AER and EMCa's forecast is discussed in section 5.4.

5.2 ElectraNet's proposal

ElectraNet proposed a forecast opex of $478.1 million for the 2013–18 regulatory control period, of which $422.8 million is controllable opex and the remainder is non-controllable opex. The proposed controllable opex is $123.8 million (or 41 per cent) higher than the actual controllable opex of the 2008–13 regulatory control period.[420]

Table 5.3 shows the increase between ElectraNet's forecast opex (2013–18) and its historical opex (2008–13). Figure 5.2 shows ElectraNet's annual opex from 2008-09 to 2017-18 by expenditure component. The large real increase in ElectraNet's proposed opex comes mostly from increases in field maintenance expenditure and higher support costs. The most significant increase in field maintenance expenditure is due to considerable increases in operational refurbishment (up 81 per cent) and corrective maintenance (up 61 per cent). ElectraNet proposed a rise in support costs of 20 per cent in total, and also proposed to introduce a new cost category: network optimisation.

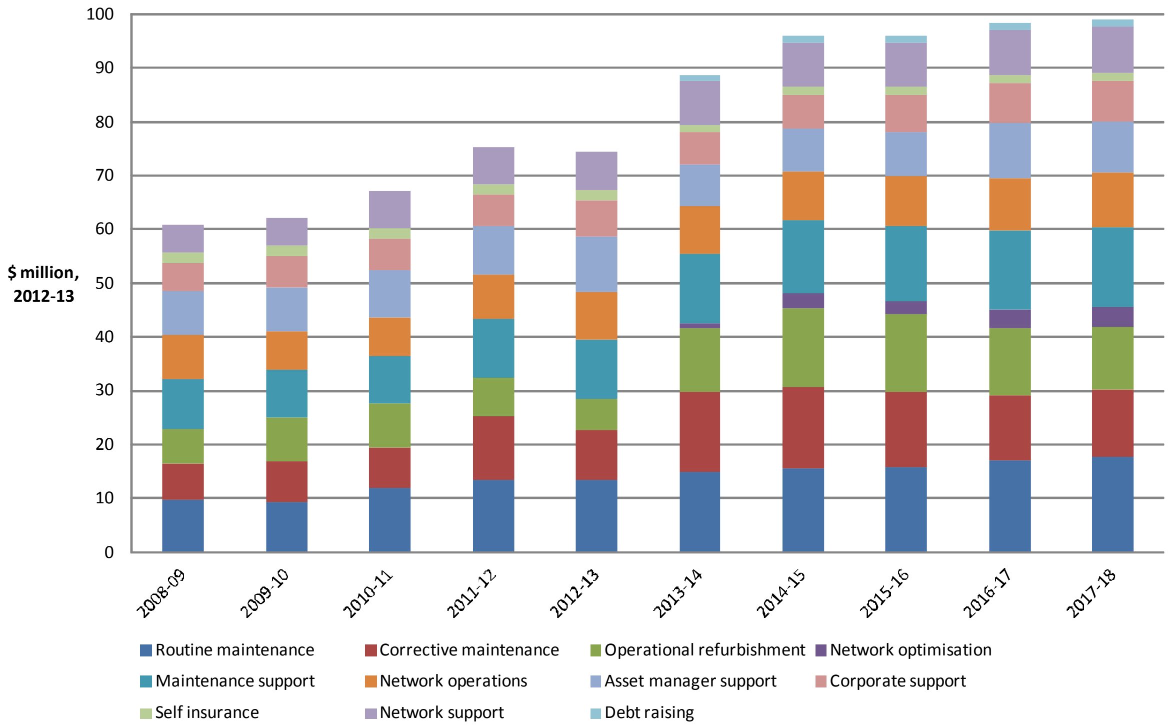
Table 5.3 ElectraNet's proposed opex increases ($ million, 2012–13)

	Opex component	2008–13	2013–18	Increase	Percentage %
Controllable opex	Field maintenance, comprising:	136.5	214.6	78.1	57
	-Routine maintenance	57.9	80.9	23.0	40
	-Corrective maintenance	42.8	68.8	26.0	61
	-Operational refurbishment	35.8	64.9	29.1	81
	Network optimisation	0.0	13.3	13.3	n/a
	Maintenance support	48.7	69.9	21.2	44
	Network operations	39.7	47.3	7.6	19
	Asset manager support	44.7	43.8	-0.9	-2
	Corporate support	29.2	33.8	4.6	16
Total controllable opex		299.0	422.8	123.8	41
Non controllable opex	Self-insurance	10.0	7.5	-2.5	-25
	Network support	31.4	41.6	10.2	32
	Debt raising costs	0.0	5.8	5.8	n/a
Total opex		**340.4**	**478.1**	**137.8**	**40**

n/a: Not applicable.
Source: AER analysis from ENET100 and ElectraNet, *Revenue proposal*, table 6.21, p. 112.

420 Costs for 2011–12 and 2012–13 are budget estimates.

Figure 5.2 ElectraNet's actual/estimated and proposed opex by category, 2008-09 to 2017-18 ($ million, 2012–13)

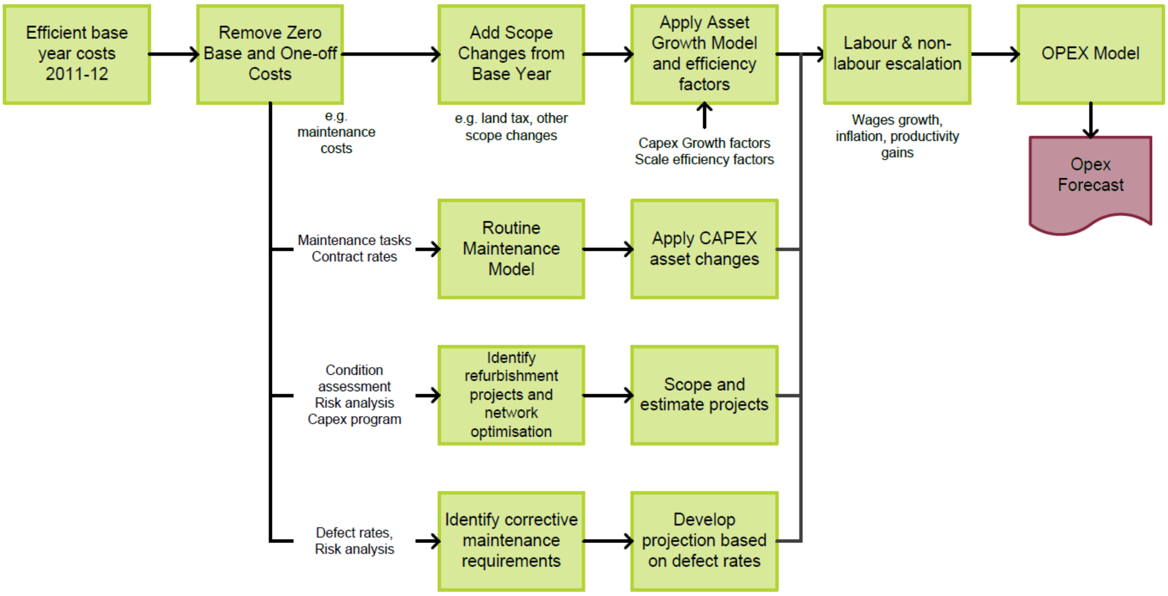


Source: AER analysis from ENET100.

5.2.1 ElectraNet's approach

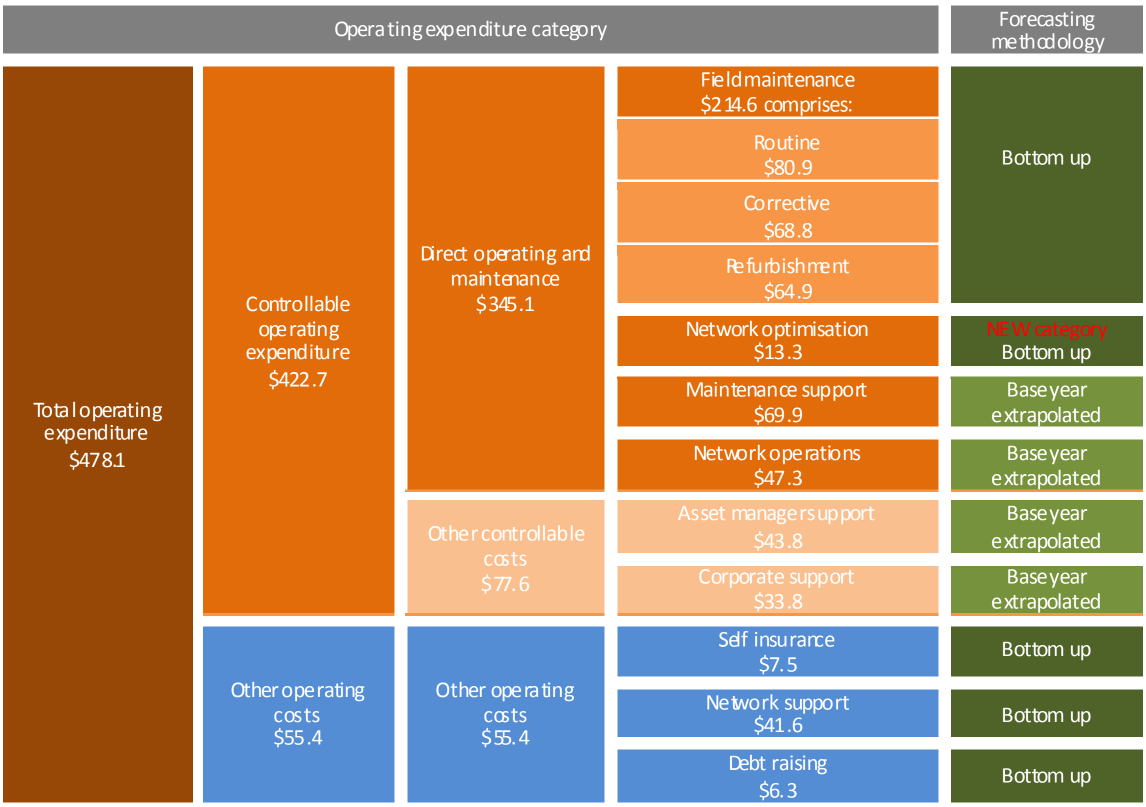
ElectraNet's transition to its integrated asset management framework is a major driver of the large increase in its proposed field maintenance costs. ElectraNet developed its opex forecast by applying one of two forecasting approaches, depending on the opex category. About 60 per cent of ElectraNet's opex forecast was derived using a bottom up approach and the remaining 40 per cent used a base-year approach. Figure 5.3 shows ElectraNet's opex forecasting method and Figure 5.4 sets the forecast approach and forecast amount for each opex component.

Figure 5.3 ElectraNet's opex forecasting method



Source: ElectraNet, ENET177, *Opex modelling methodology,* 12 June 2012, p. 6.

Figure 5.4 ElectraNet's proposed opex and forecasting method by opex category ($ million, 2012–13)



Source: AER analysis based on ElectraNet, *Revenue proposal*, Figure 6.1 and Table 6.21.

5.3 Assessment approach

The AER is required to assess ElectraNet's total forecast opex to decide whether it:

- accepts the total forecast opex, or
- does not accept it. In this case, the AER is required to estimate total required opex for ElectraNet that reasonably reflects the opex criteria, taking into account the opex factors.

The AER must accept ElectraNet's proposed forecast opex if satisfied the forecast reasonably reflects the opex criteria. That is, the forecast must reflect the efficient costs that a prudent operator in ElectraNet's circumstances would need to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the opex objectives.[421]

The AER engaged Energy Market Consulting Associates and Strata Energy Consulting (EMCa)[422] to advise on controllable opex in ElectraNet's revenue proposal.[423] It engaged Deloitte Access Economics to assess ElectraNet's labour cost escalation. EMCa developed a controllable opex forecast that it considered reasonable by making a bottom up adjustment (reduction) to ElectraNet's forecast.

The AER engaged with ElectraNet throughout the review process, including an eight day on-site workshop attended by ElectraNet, EMCa and AER staff in June–July 2012 and shorter workshops in September and October 2012. ElectraNet also presented to the AER board in August 2012. The AER and EMCa made over 200 additional requests to ElectraNet to clarify issues.

The AER also engaged with key stakeholders, including meeting with the Australian Energy Market Operator, the Essential Services Commission of SA, SA Power Networks (formerly ETSA Utilities) and South Australian Water. It sought public submissions on ElectraNet's proposal and held a public forum in July 2012. The AER received submissions from the South Australian Council of Social Service, the Energy Consumers Coalition of South Australia, the Clean Energy Council and the Energy Users Association of Australia and the SA Minister for Mineral Resources and Energy. Further, it examined key documents, processes and assumptions, and compared historical expenditure to that proposed, to understand the key drivers behind ElectraNet's proposed forecast opex

The AER developed a top down forecast for the total opex program, based on its revealed costs method (the base-year-extrapolated approach). It used the top down forecast to inform its decision on whether ElectraNet's proposed opex reasonably reflects the opex criteria. If part of the proposed total forecast is significantly higher or lower than the AER's base year forecast, then the AER cannot be satisfied that that the forecast reasonably reflects the opex criteria, having regard to the opex factors.

The regulatory regime provides incentives for ElectraNet to deliver prescribed services at least cost. In particular, if ElectraNet can provide its services at a lower cost than the forecast opex allowance, then it can 'keep the difference' for five years as provided under its opex incentive mechanism, the efficiency benefits sharing scheme (EBSS). Given these incentives, actual opex reveal the efficient level of opex required to provide prescribed services. Rather than having to assess all aspects of opex, therefore, the AER can instead focus on changes needed for the base level of opex. In particular, once the base year is set, the AER assesses only the following adjustments:

- step changes, to provide an additional opex allowance when a certain circumstance, requirement or project requires the business to undertake expenditure that is not incorporated in the base year

421 NER, clause 6A.6.6(c).

422 This attachment refers to Energy Market Consulting Associates and Strata Energy Consulting collectively as EMCa.

423 The scope for this review is set out in the AER's 'Terms of reference for technical consultant and demand forecast consultant'.

- annual cost trends, to account for forecast labour and material cost changes, network growth and scale efficiencies.

The AER reconciled its top down forecast and EMCa's bottom up analysis to understand the efficient opex costs that a TNSP in ElectraNet's circumstances would need to incur to achieve the opex objectives.

5.4 Reasons for draft decision

The AER is not satisfied the total forecast opex proposed by ElectraNet reasonably reflects the opex criteria, having regard to the opex factors.[424] For this reason, it applied a substitute opex forecast for the 2013–18 regulatory control period.[425] In coming to its draft decision, the AER reviewed ElectraNet's proposal using two approaches:

- a top down approach (section 5.4.2)
- a detailed bottom up technical review (section 5.4.3).

Both reviews show ElectraNet's proposed forecast opex for the 2013–18 regulatory control period is more than is reasonably required to meet the opex criteria for the reasons set out in this section.[426]

Further, the opex criteria which require the AER to be satisfied that ElectraNet's opex forecast is a realistic expectation of the demand forecast and cost inputs reasonably required to achieve the opex objectives. But the AER does not accept ElectraNet's demand forecast and substituted its own demand forecast (attachment 2).

In its submission on ElectraNet's proposal, EUAA set out its concerns about the magnitude of ElectraNet's proposed opex increases. EUAA noted that ElectraNet's proposed opex would result in its opex/MWh more than doubling from the start of the 2008–13 regulatory control period to the end of the 2013–18 regulatory control period.[427] In light of the proposed 40 per cent increase in opex, the EUAA highlighted the 'need for the AER to undertake a thorough review, informed by benchmarking, of each element of ElectraNet's opex, including field maintenance, operational refurbishment, asset management support, corporate support, maintenance support and network operations'.[428] ECCSA observed 'there is little in ElectraNet's reasons to justify a step change in opex of the size requested by ElectraNet'.[429]

5.4.1 AER's substitute forecast

The AER used the top down forecast (developed in section 5.4.2) as its substitute controllable opex forecast. Table 5.4 sets out four controllable opex forecasts:

- ElectraNet's proposed opex forecast, which combines bottom up and top down approaches and used 2011–12 as the base year
- AER's top down forecast, based on revealed costs but with no step changes, includes efficiency adjustment

424 NER, clauses 6A.6.6(d) and 6A.6.6(e).
425 NER, clause 6A.6.6(f).
426 NER, clause 6A.6.6(c).
427 EUAA, *Submission to ElectraNet's revenue proposal 2012–13*, August 2012, p. 14.
428 EUAA, *Submission to ElectraNet's revenue proposal 2012–13*, August 2012, p. 14.
429 ECCSA, *Submission to ElectraNet's revenue proposal 2012–13*, August 2012, p. 33.

- AER's substitute forecast, with step changes for ElectraNet's new asset management strategy and including efficiency adjustment.
- EMCa's adjusted forecast, which is based on its bottom up adjustments to ElectraNet's total forecast[430]

Table 5.4 Total opex forecast: AER, ElectraNet, and EMCa for 2013–18 ($ million, 2012–13)

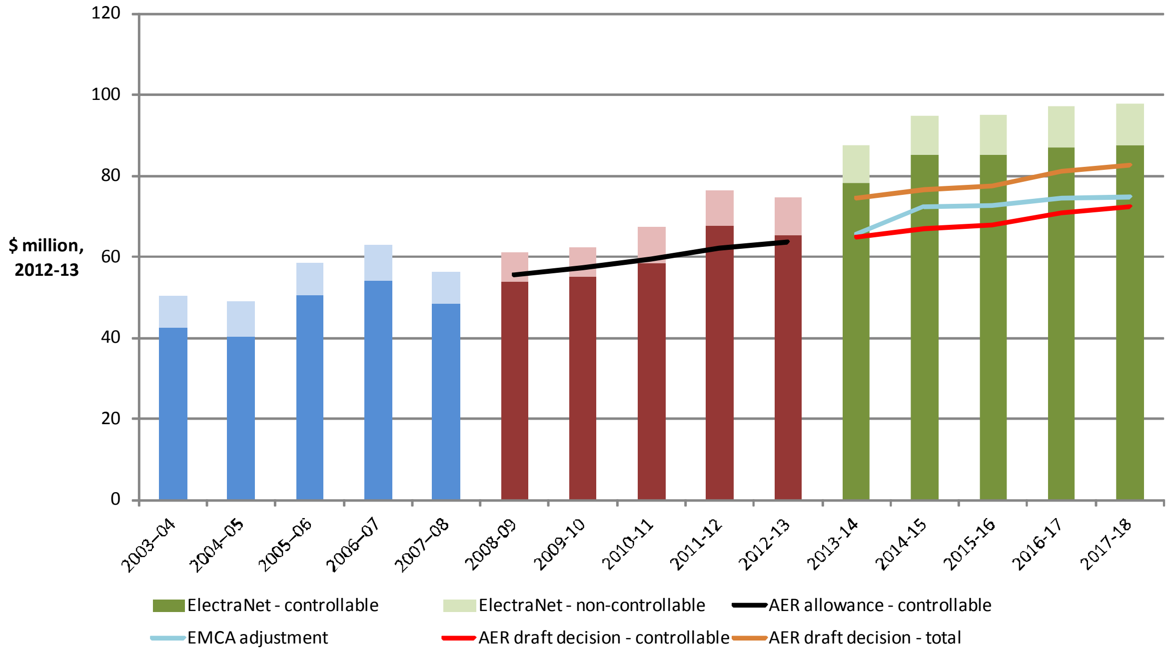
	ElectraNet proposed	AER's revealed costs	AER's substitute forecast	EMCa adjusted*
Routine maintenance	80.9	71.4	80.9	78.5
Corrective maintenance	68.8	43.5	43.7	47.4
Operational refurbishment	64.9	46.8	47.0	48.5
Network operations	47.3	40.2	40.2	38.4
Maintenance support	69.9	48.5	48.6	63.1
Asset manager support	43.8	52.0	51.7	39.5
Corporate support	33.8	31.1	31.4	30.5
Network optimisation	13.3			13.3
Total controllable opex	**422.8**	**333.5**	**343.5**	**359.2**
Self insurance	7.5	n/a	6.8	7.5
Network support	41.6	n/a	41.6	41.6
Debt raising costs	6.3	n/a	5.8	6.3
Total non-controllable opex	**55.4**	**n/a**	**54.2**	**55.4**
Total	**478.1**	**n/a**	**397.6**	**414.6**

Note: n/a:not applicable, revealed costs was not used as these were zero based categories.
EMCa forecast included an adjustment for support, efficiency and asset growth. These have been prorataed against the relevant category.

Source ElectraNet, *Revenue proposal*; EMCa, *ElectraNet technical review*, October 2012; AER analysis.

430 Includes EMCa's proposed adjustments plus the AER's bottom up adjustment for network optimisation and land-tax.

Figure 5.5 Total opex forecast 2003–13 ($ million, 2012–13)



Source: AER analysis.

The AER's substitute controllable opex forecast ($343.5 million) is $15.7 million less than EMCa's forecast ($359.6 million). In developing its forecast, the AER used a revealed costs approach, which assumes efficient and recurrent costs are provided for through the extrapolation of efficient base year costs. EMCa took ElectraNet's total forecast as a starting point, reviewed ElectraNet's assumptions and inputs and developed a series of (bottom up) adjustments to ElectraNet's forecast. EMCa assumed ElectraNet's real cost escalation. As such, most of the difference between the AER's substitute forecast and EMCa's forecast results from the analysis of the controllable opex expenditure. network optimisation expenditure catgory ($13.3 million), which EMCa accepted in its bottom up forecast, but the AER did not accept in its top down forecast. Most of the remaining differences comes from the different assumptions of real cost escalation.

EMCa consider that it is appropriate that ElectraNet has established network optimisation as a new opex category.[431] The AER agrees with EMCa that this is 'expenditure that is expected to deliver outcomes that meet ElectraNet's objective of improving the capability of the transmission ElectraNet'.[432] However, the AER has not accepted this category of expenditure as a 'new' category (step change) in ongoing requirements. In ongoing requirements under the AER's revealed cost approach iun forecasting the substitute allowance. Further, ElectraNet proposed this category because it will achieve capex-opex deferrals but ElectraNet have not identified which projects will be deferred, by how much and within what timeframe. On this issue, EMCa noted:[433]

> Given that detailed business cases for the components of Network Optimisation have yet been produced, it will be important that expected benefits are quantified and the performance of programs monitored. It would be desirable that performance, in terms of delivery of expected benefits for network optimisation programs, should be reported by ElectraNet in their revenue proposal for the subsequent regulatory control period.

Full discussion of the AER's reasons for not accepting network optimisation as a new category are set out in appendix A.

431 EMCA, *ElectraNet technical review,* October 2012, pp.134–135.
432 EMCA, *ElectraNet technical review,* October 2012, pp.134–135.
433 EMCA, *ElectraNet technical review,* October 2012, pp.134–135.

5.4.2 AER's top down assessment

ElectraNet's controllable forecast opex was significantly higher than the AER's top down assessment, so the AER further tested the reasonableness of ElectraNet's forecast. Table 5.5 shows ElectraNet's proposed controllable opex forecast is $89.3 million higher than the revealed costs historical trend line and $79.4 million higher than the AER's base-year-extrapolated forecast with step changes and efficiency adjustment.

Table 5.5 AER's top down assessment of controllable opex ($ million, 2012–13)

Method	2013–14	2014–15	2015–16	2016–17	2017–18	Total
AER's top down forecast (historical trend line)	62.6	65.7	66.6	68.9	69.7	333.5
AER's base year extrapolated model, with step changes and efficiency adjustment [A]	64.5	67.6	68.6	70.9	71.9	343.5
ElectraNet's proposal [B]	78.1	85.0	85.2	87.0	87.5	422.8
Difference [B–A]	13.7	17.4	16.7	16.1	15.6	79.4

Source: AER analysis.

The AER reviewed ElectraNet's expenditure during the 2008–13 regulatory control period to test whether it was efficient and appropriate for use as the base year expenditure using a base year forecasting approach. The AER considered the incentives faced by ElectraNet during the 2008–13 regulatory control period, benchmarked ElectraNet's opex and assessed its base year expenditure.

Efficiency of historical expenditure

The AER used a top down revealed costs approach to assess the efficiency of ElectraNet's forecast controllable opex.[434] That is, the AER used ElectraNet's historical controllable actual opex in determining a recurrent base year to assess whether ElectraNet's proposed total forecast opex reasonably reflects the opex criteria, having regard to the opex factors. The incentive regime is premised on revealed costs (not a cost of service regime). This approach is well accepted in Australia, and has been applied by ElectraNet in the past. Under the NER's chapter 6A incentive regime, TNSPs are subject to an EBSS and a revenue cap control mechanism. That is, the regime provides incentives to reduce opex because TNSPs can retain any cost savings made during the regulatory control period. While this incentive to reduce expenditure declines over the period, the application of the AER's EBSS provides TNSPs with a continuous incentive to make savings. The revenue cap control mechanism also delivers savings to TNSPs because revenue is fixed during the regulatory control period, so the TNSP retains any cost savings. The EBSS and the revenue cap control mechanism interact to incentivise service providers to undertake opex that meets the opex objectives. The AER considered these mechanisms in developing its top down assessment.

The AER considers the revealed costs approach appropriate because, the opex allowance for the 2008–13 regulatory control period was approved as being the efficient allowance that a prudent TNSP in ElectraNet's circumstances would be expected to incur. ElectraNet expects to manage its controllable opex in the current regulatory period to fall within 0.5 per cent of its total controllable allowance over the period.[435] This performance shows ElectraNet was not limited in its opex program in the current regulatory control period. Further, ElectraNet demonstrated in previous regulatory

[434] The AER assessed non-controllable opex items using a bottom–up approach.
[435] ElectraNet, *Revenue proposal*, p. 42.

control periods (including the current regulatory period of 2008–13) that it can manage its business and achieve its high service targets operating at these costs levels. Its current high service levels are a good indication of performance.

ElectraNet's asset management strategy[436] is aligned over three regulatory periods: 1 January 2003 to 30 June 2008, 2008–13 and 2013–18. This alignment suggests a link between revealed costs and forecast costs. ElectraNet is developing its asset profiles, which will be completed half way through the 2013–18 regulatory control period (for transmission lines).[437] It thus based its bottom up forecast on data that is still being collated. This situation supports the continuing use of base year costs for transmission lines.[438] ElectraNet also used a revealed costs approach to develop some categories of its proposed forecast: asset management, network operations, maintenance support and corporate support.

Benchmarking

The AER must have regard to the benchmark expenditure of an efficient TNSP when assessing proposed TNSP forecast opex against the opex criteria. Benchmarking provides an indication of the relative performance of TNSPs and can be used to form a view about the efficiency of ElectraNet's historical costs. Benchmarking has played a role in previous AER revenue determinations, and is used by other regulators such as the United Kingdom's Office of the Gas and Electricity Markets (Ofgem).

In considering an efficient benchmark opex, there are two key factors the AER can adjust for: density and size. More opex is typically required for less dense networks, partly due to increased travel costs. Size is important because larger TNSPs will benefit from economies of scale. The AER used load density (megawatts per kilometre of line) to normalise the results. The AER considers load density is the appropriate measure given the size in TNSPs differs substantially. The AER compared the level of ElectraNet historical opex against other TNSPs in the NEM using ratio analysis. The full analysis is set out in appendix B.

Base year

ElectraNet proposed 2011–12 as the base year for the 40 per cent of its forecast opex that used a base-year-extrapolated approach. The majority of ElectraNet's forecast opex was based on a bottom up (zero-based) approach, which means the proposal is not readily linked to historical revealed costs. For its base-year-extrapolated forecast ElectraNet proposed the fourth year of the 2008–13 regulatory control period, 2011–12, as the base year. The AER does not agree that 2011–12 represents efficient or recurrent costs, so it instead applied 2010–11, which it considers is an efficient recurrent base year. In its proposal, ElectraNet estimated its opex costs for 2010–11 but submitted its audited regulatory accounts to the AER on 31 October 2012. Due to time constraints, the AER used ElectraNet's estimated costs for 2010–11 in its analysis for the draft decision, but this data will be updated in the final decision.

The AER considers 2011–12 is not a year reflective of typical recurrent and efficient costs. Figure 5.6 shows ElectraNet's controllable opex (actual and proposed) compared with its allowance and the revealed costs trend line.[439] It shows ElectraNet's actual expenditure in 2011–12 was notably above

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436 ElectraNet, *Revenue proposal*, p.92; ElectraNet, *Response to EMCa information request 014-015*, ENET180 [public version].

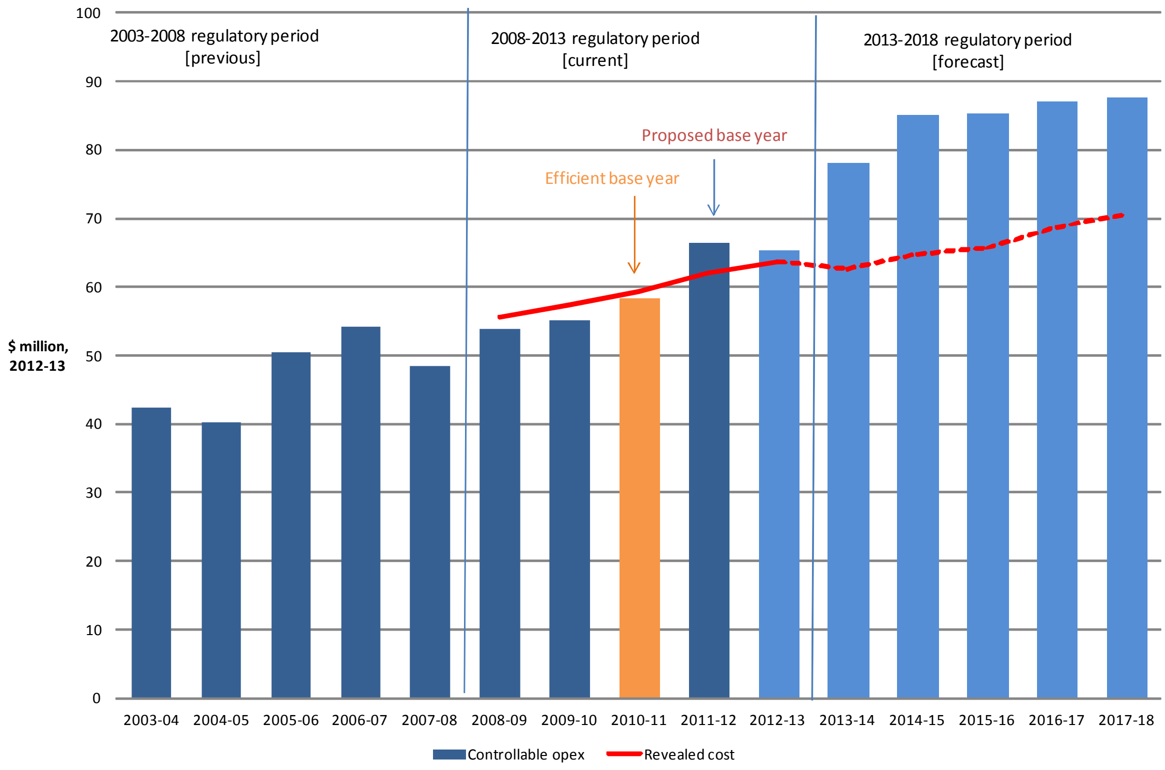
437 ElectraNet expects to complete the first round of substations life cycle profiles by the end of the 2008–13 regulatory control period.

438 Transmission line assessments are less advanced than substation asset life assessments.

439 No step changes have been included.

its allowance and is well above the average for 2008–13. Controllable opex remained relatively stable in the first three years of the 2008–13 regulatory control period, but then clearly stepped up for the final two years of the period (2010–11 and 2011–12). When there is a distinct step change from the previous three years, the use of 2011–12 as the base year (the fourth year) may upwardly bias the forecast. In comparison, most of the 2010–11 costs (by opex category and as a whole) were closer to trend and average; suggesting 2010–11 is more representative of recurrent costs.

Figure 5.6 ElectraNet's controllable opex, AER allowance and revealed costs trend line ($ million, 2012-13)



Source: AER analysis.

ElectraNet explained that the increased costs towards the end of the 2008-13 regulatory control period were due to its restructured business operations, increased aerial inspection program, implementation of its new maintenance regime, and additional vegetation management requirements.[440] The AER notes these reasons include a significant portion of 'one-off' business implementation and transformation costs, and these reasons help explain why 2010–11 is a year better reflective of recurrent costs than 2011–12.

In its technical review, EMCa also found that ElectraNet's proposed expenditure is upwardly biased by the choice of 2011–12 forecast expenditure as a base year. EMCa specifically commented on the 40 per cent of ElectraNet's forecast opex that was base-year-extrapolated. EMCa observed the step change increases in maintenance support expenditure (steady at about $9 million for the first three years then stepping up to $11 million for the fourth year) and network operations expenditure (steady at about $7.2 million in the first years and then increasing to $8.3 million in the four year). EMCa

440 ElectraNet, *Revenue proposal*, p. 42.

estimated the change in base year (from 2011–12 to 2010–11) for the proportion of ElectraNet's proposal that was base-year-extrapolated is in the order of $17.5 million.[441]

The EUAA's submission on ElectraNet's proposal disagreed with ElectraNet's use of 2011–12 as the base year and considered it inconsistent with the intent of the EBSS. The EUAA submitted that 2010–11 is a more appropriate base year since it matches more closely the average opex for the 2008–13 regulatory control period:[442]

> The EUAA also noted that the year ElectraNet has chosen (2011–12) is the highest opex year for the 2008–13 regulatory control period. The EUAA expressed concerns that 2011–12 is not a 'normal or efficient operating cost year' and urged the AER to examine this issue closely and ensure that a year is chosen that is truly representative of efficient opex.

The ECCSA, in its submission on ElectraNet's proposal, also discussed ElectraNet's choice of base year and the EBSS regime:[443]

> To develop its forecast controllable opex, ElectraNet has based its forecast on its expected opex for 2011–12, even though this is, in part, a forecast. This estimate is the highest annual opex cost the [2008-13 regulatory control period]. Assuming the forecasts are correct, the average annual opex for the [2008-13 regulatory control period] is ... 10 per cent lower than the opex used as the base. This reinforces concern about the practice of using a known year as the base year for future opex claims as the practice encourages “gaming” of the system. The ECCSA considers that (as does now, apparently, the AER) using the average opex over the regulatory period, provides a more representative value for opex to use as the basis for forecasting future opex.

The ECSAA raised particular concerns with ElectraNet's forecast method, because of the large proportion of controllable opex based on a bottom up assessment without reference to past performance. ECSAA observed that this 'raises serious concerns about the use of the EBSS to drive opex to efficient levels'. ECCSA did not support the approach having part of the opex allowances calculated using a base-year-extrapolated and the balance calculated using a zero-based approach and noted 'the continual use of zero based calculations removes the comparisons essential to ensure that allowances are efficient. As the EBSS is designed to incentivise more efficient opex, exclusion of half the opex from this driver, reduces the value of the incentive program'.[444] The AER agrees and used both a top down and bottom up approach to assess ElectraNet's forecast opex.

The EBSS and the revenue cap control mechanism provide incentives for ElectraNet to continuously make cost savings but the choice of base year impacts the size of the accrued penalty or reward but the choice of base year can influence the forecast opex and the EBSS penalty or reward. ElectraNet submitted that it chose 2011–12 as a base year because this would be consistent with the AER's previous decisions and with the terms of the new EBSS scheme (which does not currently apply to ElectraNet). The AER considered the incentive framework in its analysis and choice of the efficient base year. In particular, the AER calculated the outcome on ElectraNet's forecast opex allowance–including any impact driven by EBSS adjustments–for both the 2010–11 and 2011–12 base year. ElectraNet's penalty is $26.9 million if 2011–12 is used as the base-year, driven by its large over expenditure in 2011–12 compared with its allowance. On the other hand, the EBSS penalty is smaller ($4.5 million) when the 2010–11 base year is used. Although the AER, in using 2010–11 as the base year, is reducing ElectraNet's EBSS penalty, there is an off-setting impact on its opex allowance for the 2013–18 regulatory control period and thereafter. Changing the base year also means ElectraNet's future opex requirements are determined according to a base-year that better reveals

441 EMCa, *ElectraNet technical review*, October 2012, table 22, p. 142.
442 EUAA, *Submission to ElectraNet’s revenue proposal*, August 2012, p. 15.
443 ECCSA, *Submission to ElectraNet’s revenue proposal*, August 2012, p. 35.
444 ECCSA, *Submission to ElectraNet’s revenue proposal*, August 2012, pp. 35–36.

efficient and recurrent costs.[445] The interaction of the base year and the EBSS is further discussed in attachment 12.4.1.

The AER adjusted the 2010–11 base year financial information to remove regulatory compliance expenses and movements in provisional accounts because these do not represent recurrent costs. However, these were the only adjustments the AER made to the base year. In general, a TNSP, for any one year, is likely to have some costs that are higher than business-as-usual and some costs that are lower. While ElectraNet's opex in one cost category might have been lower in the base year, other opex categories were likely higher. Many factors influence actual opex in any one year in both directions, so the AER considers a forecast of total opex is more likely to include estimation errors if it does not reflect of all opex incurred in a financial year. To the extent that any costs were lower (higher) than average in the base year, ElectraNet will be rewarded (penalised) through its opex EBSS incentive mechanism. In other words, ElectraNet will retain any cost reductions (increases) in its base year for a five year period. To then adjust the base year would lead to over (under) compensation.

Further analysis of the base year is set out in appendix A.

Step changes

The AER is not satisfied all of ElectraNet's proposed step changes reasonably reflect the efficient costs of a prudent TNSP in ElectraNet's circumstances[446] or the efficient costs of achieving the opex objectives.[447] The AER's substitute forecast allows for an additional $10 million[448] above the revealed cost trend for step changes. This is the net effect of the step changes: some step changes were for increases in opex allowance but others were step change decrements. These are discussed in appendix A.

ElectraNet proposed a step change increase in its field maintenance requirements[449] (driven by its significant investment in its new integrated asset management regime), for new accommodation, superannuation and a new cost category called network optimisation. The major proposed amendment is for field maintenance costs; ElectraNet proposed a total field maintenance opex of $214.6 million, which is a step-change increase of $52.9 million on the revealed cost trend, plus an additional $13.3 million for a new category of opex (network optimisation).[450] The other step changes proposed summed to $15.4 million.

The AER also applied step change decrements. In accordance with the *Electricity Act 1996 (SA)*, the Minister for Mineral Resources and Energy announced his intention to reduce the annual transmission fee licence by 32 per cent for the 2013–18 regulatory control period.[451] The AER reduced ElectraNet's proposed opex forecast by $4.9 million accordingly.[452]

445 ElectraNet incorrectly calculated its EBSS carryover amount (attachment 12).
446 NER, clause 6A.6.6(c).
447 NER, clause 6A.6.6(a) and (c).
448 Does not include the 2.5 per cent efficiency factor.
449 ElectraNet proposed its field maintenance opex forecasts as zero-based cost categories that significantly exceed the historical cost trend. The AER has considered the difference over historical cost as an 'incremental' step change.
450 These figures are the total impact of the step change after it has been escalated.
451 Honourable Tom Koutsantonis MP, Member for West Torrens, *Submission to AER,* 27 September 2012.
452 This is the total savings across the 2013–18 regulatory control period based on a reduction of $800,000 in the base year 2010–11 and estimated as a reduction of $800,000 per annum for five years, escalated.

Escalation for network growth

Asset growth

ElectraNet applied asset growth factors to escalate its base year opex to account for its expanding network. It based the proposed asset growth factors on the depreciated regulated asset base (RAB) values in the base year. The AER does not accept ElectraNet's method for estimating asset growth because that method overestimated the forecast opex. The depreciated RAB value underestimates the physical size of ElectraNet's network in the base year, and thus the asset growth factors calculated using that value overestimated the network growth rates. This overestimation occurs because the depreciated RAB value is used as the denominator when calculating the asset growth factors. Instead, the AER applied an estimated undepreciated RAB. The AER has requested ElectraNet to provide an estimated undepreciated RAB value to the AER for the purposes of asset growth calculation. However, ElectraNet responded that it does not have an undepreciated RAB value.[453] The AER therefore has estimated an undepreciated RAB value for 2010–11 by adding the accumulated straight-line depreciation from 2002 to 2010 to the depreciated RAB value at 30 June 2011. The AER updated the asset growth factors to reflect the AER's draft decision on load driven capex, because load-driven capex is used as an input for calculating the asset growth factors.[454] It also removed the impact of real cost escalation from the asset growth factors to avoid double counting because real cost escalation has been separately accounted for in the opex model.

Economies of scale

ElectraNet's proposed asset growth factors incorporate economies of scale factors. This is because asset growth does not result in a one for one increase in operating expenditure for all operating cost categories. However, ElectraNet changed its economies of scale factors from 25 per cent to 40 per cent for network operations and from 10 per cent to 25 per cent for its asset manager support, meaning that it expects to be less efficient in future than currently. The materiality of these changes is about $1.7 million.

The AER is not satisfied ElectraNet's reason for the increase in scale factors is sufficient to demonstrate the proposed opex forecast is a realistic expectation of cost inputs. ElectraNet noted its changes are in line with the AER's recent decision for Powerlink's 2012–17 revenue determination, but increased its scale factors based on its 'experience and judgement'. The AER does not accept the ElectraNet will be less efficient than current circumstances and therefore adopted the same economies of scale factors approved for the 2008–13 regulatory control period.

ElectraNet proposed an economies of scale factor of 100 per cent for its direct charges. Direct charges falls within the maintenance support category which has an economies of scale factor of 25 per cent. ElectraNet stated that direct charges such as land tax have no efficiencies available as they are externally driven and directly proportional to asset growth. The AER note that land tax forms a large proportion of the costs in this sub-category. Since land tax is forecast using a zero-based method, it does not require an economies of scale factor. For the remaining direct charges, the AER applied an economies of scale factor of 25 per cent, which is consistent with the economies of scale factor of the maintenance support category.

453 ElectraNet, *Email response to information request AER RP36 opex model assumption*, ENET278, p. 4.

454 Based on as-commissioned load driven capex. ElectraNet, *Email response to information request AER RP36 opex model*, ENET273, p. 2; ElectraNet, *Email response to information request AER RP36 opex model*; ENET278, p. 4.

Table 5.6 Economies of scale factors for asset growth (per cent)

	2008–13	ElectraNet proposed 2013–18	AER 2013–18
field maintenance	95	95	95
maintenance support	25	25	25
direct charges	100	100	25
network operations	25	40	25
asset manager support	10	25	10
insurances	-	-	-
corporate support	10	10	10
other	-	-	-

Source: AER analysis.

Labour and materials cost escalators

As discussed in section 1.1 the AER amended ElectraNet's real cost escalators which impacted the AER's draft decision on ElectraNet's forecast opex. Refer to attachment 1 for more details on cost escalation.

Opex efficiency factor

The AER is not satisfied ElectraNet's forecast opex reasonably reflects the efficient costs of achieving the opex objectives because the base-year opex does not capture the removal of all current and existent inefficiencies. The AER applied an opex efficiency factor of 2.5 per cent to the base year (and thus to the controllable opex forecast) for the following reasons.

ElectraNet recognised the scope for continuous improvement and has introduced a formalised improvement and innovation program under which it identified inefficiencies in its current practices and implemented solutions to reduce such inefficiencies. It outsources all its field maintenance activities, for example, and its field maintenance contract with SA Power Networks includes financial incentives linked to specified performance targets. These arrangements allow for forward maintenance works to be scheduled in conjunction with capital works, works in remote areas to be co-ordinated to reduce travel time, and defects to be fixed 'on the spot' when the fix can be done in the time allocated for inspection and routine work.[455] ElectraNet identified efficiency savings for the majority of routine maintenance of the order of five per cent.[456] The AER considers ElectraNet can reasonably be expected to achieve efficiencies in other areas of other field work and support functions too. These efficiency savings have been realised in the latter part of the 2008–13 regulatory control period but are not reflected in the 2010–11 base year, which is the basis of the AER's substitute forecast.

The AER does not agree with ElectraNet's claim that allowing for the removal of inefficiencies in the regulatory forecasts would weaken the incentive properties of the regulatory regime. The EBSS

455 EMCa, *ElectraNet technical review,* October 2012, paragraph 530.
456 EMCa, *ElectraNet technical review,* October 2012, paragraph 531.

incentive regime operates on variances in controllable opex relative to the allowance assessed for regulatory purposes. The incentive is not affected by the level at which controllable opex was assessed for regulatory purposes. Moreover, the AER's efficiency adjustment does not undermine the incentive regime because the AER is removing only the existing identified inefficiencies. ElectraNet's ongoing management effort would achieve further efficiencies over the regulatory control period, and they would be part of the EBSS.

ElectraNet proposed a capex allowance of one to two per cent efficiency improvement in its proposed capex program, but not an opex efficiency factor. Yet opex efficiencies are comparatively easier to identify and achieve than capex efficiencies so it is not clear to the AER why ElectraNet could identify future capex, but not further opex, efficiencies. [457] Given opex efficiencies are 'easier' to identify and address, the opex efficiency factor that the AER applies should be no less than the capex efficiency factor proposed.

Under the NER framework, efficiency incentives provide a commercial incentive for TNSPs to improve efficiency.[458] For the 2008–13 regulatory control period, ElectraNet achieved opex efficiencies of 2.9 per cent (relative to the AER determination), in the three years of actual expenditure: 2008-09, 2009-10 and 2010–11[459]. Given the existence of the established program, EMCa found the benefits will be available from the start of the 2013–18 regulatory control period, based on actions already underway.[460] EMCa considered it reasonable to assume a 2.5 per cent efficiency allowance across all opex, and that this will occur from the beginning of the 2013–18 regulatory control period, given ElectraNet's existing continuous improvement mind set, the structured improvement program and the commercial incentives that exist.[461]

5.4.3 Technical review

The AER engaged EMCa to advise on ElectraNet's controllable opex proposal.[462] The AER also assessed other elements of the proposal (such as non-controllable opex) from a bottom up perspective.

EMCa's technical review showed that ElectraNet's controllable opex forecast, in many areas, was higher than the forecast that EMCa considered reasonable. EMCa recommended reducing ElectraNet's proposed forecast by around $63.2 million. For this reason, the AER is not satisfied ElectraNet's forecast reasonably reflects the opex criteria, which require the forecast to reflect the efficient and prudent costs of a TNSP for achieving the opex objectives.[463] Furthermore, the AER found the proposed new opex category, network optimisation, does not meet the opex criteria.[464]

Overall, EMCa found ElectraNet demonstrated it had adopted detailed asset management policies to develop high level strategies for network development and maintenance, and detailed asset strategies to guide and inform the business on asset management decisions.[465] It found ElectraNet had adopted and built on well proven asset management systems and can demonstrate its planning is based on

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457 EMCa, *ElectraNet technical review,* October 2012, paragraph 358.
458 Efficiency Benefit Sharing Scheme (EBSS).
459 ElectraNet forecast an increase in opex in the final two years of the regulatory control period because 'increased asset management requirements have emerged (RP, page 84), such that its controllable opex over the whole of the current regulatory control period would be essentially as per the AER's previous decision. As noted, however, ElectraNet also explained that work had been 'brought forward' into the current regulatory control period with an implied view that it would be commercially prudent to spend up to the 'allowance' contained in the AER's previous decision.
460 EMCa, *ElectraNet technical review,* October 2012, paragraph 537
461 EMCa, *ElectraNet technical review,* October 2012, paragraph 537.
462 The scope for this review is set out in the AER's 'Terms of reference for technical consultant and demand forecast consultant'.
463 NER, clause 6A.6.6(c).
464 NER, clauses 6A.6(c)(1)-(2).
465 EMCA, *ElectraNet technical review,* October 2012, Finding 1, p. 12.

intelligent asset management strategies supported by increasingly reliable data.[466] However, from its review of ElectraNet's asset management governance structure and capital expenditure (capex) and opex forecasting processes, EMCa found aspects of the new asset management regime were not sufficiently rigorous to lead to the proposal of some opex items.[467] Table 5.7 sets out EMCa's recommended adjustments.

Table 5.7 EMCa's recommended adjustments to ElectraNet's controllable opex forecast for the 2013–18 regulatory control period ($ million, 2012–13)

	Adjustment	Total controllable opex 2013–18
ElectraNet forecast opex		**422.8**
Adjustment:		
Corrective maintenance		
Lines	-11.2	
Substations	-8.2	
Operational refurbishment	-14.5	
Support	-13.3	
Network operations	-4.2	
Opex efficiency	-10.6	
Asset growth	-1.3	
Total adjustment (factors applied individually)	**-63.3**	
Total cumulative adjustments		**-63.2**
Adjusted controllable opex		**359.6**

Source: EMCa, *ElectraNet technical review*, October 2012, table 22, p. 142.

Routine maintenance

ElectraNet proposed a 40 per cent increase in its routine maintenance program, from $57.9 million in 2008–13 to $80.9 million in 2013–18. It submitted that this increase is the result of increased inspections, which in turn is driven by the implementation of its new integrated condition-based asset management framework.

The AER accepts ElectraNet's proposed routine maintenance forecast because ElectraNet presented evidence of having thoroughly considered routine maintenance requirements.[468] The AER generally supports the integrated asset management framework that ElectraNet has begun to deploy, because such a regime can facilitate lifecycle management of risks in a transparent and cost effective manner. ElectraNet presented evidence of its continuous improvement program resulting in innovation and efficiency improvements of five per cent in the routine maintenance program.[469]

[466] EMCa, *ElectraNet technical review,* October 2012, Finding 1, p.12.
[467] EMCa, *ElectraNet technical review,* October 2012, Finding 8,9, p.18-19.
[468] EMCa, *ElectraNet technical review*, October 2012, p. 139, paragraph 530.
[469] EMCa, *ElectraNet technical review*, October 2012, p. 139, paragraph 351.

The AER considered ElectraNet's field maintenance activities in tandem and in context of its capex program. The AER accepts ElectraNet's reasoning that increasing its routine maintenance expenditure should result in future benefits in other field maintenance areas, such as the corrective maintenance program. That is, by better understanding and maintaining assets (through routine maintenance), the more costly consequences of ad hoc corrective maintenance can be avoided. Therefore the corrective maintenance expenditure should decrease over time as a result of the increased routine maintenance expenditure.

Corrective maintenance

ElectraNet proposed $23 million for corrective maintenance of substations and $40 million for corrective maintenance of transmission lines. It presented costs in two forms: a backlog of already identified defects and a base level of defects. This represents an increase of $25.3 million on top of the revealed cost trend line.[470] The AER found ElectraNet's proposed corrective maintenance expenditure does not meet the opex criteria[471] for the reasons set out in this section. The AER used the revealed costs for corrective maintenance in its substitute forecast (that is, $43.7 million).

ElectraNet overstated its corrective maintenance forecast because it did not properly allow for reductions in the rate of new defects that will arise once the first round of the condition assessment cycle is complete. ElectraNet is only part way through its first assessment cycle, which is prioritised to address high risk defects first (such as fire start defects) and further defects in descending order of risk. As the high risk defects are progressively addressed, fewer new defects will arise in subsequent inspection cycles. However, as the program matures, the ongoing opex requirements should trend downwards to a base level. This trend should be most evident in corrective maintenance costs over time, and ElectraNet submitted the aim of the program is to minimise corrective maintenance costs.[472] For this reason, the rate of incoming defects should decrease over time because the incoming trend will be towards defects with lower risk and longer timeframes. But ElectraNet's forecast of incoming defect rates was overstated because it was based on the average of the first two years of incoming high risk defect data, which represents an upward bias, and did not account for the decreasing trend.

ElectraNet submitted that the decreasing trend of rate of incoming defects rates, was offset by the 'bath tub effect', which is an increased expenditure requirement at the start and end of asset life. But the AER disagrees that the bath tub effect off sets ElectraNet's decreased corrective maintenance requirements. Modern substation equipment generally minimises this effect because it is modular, prefabricated and pretested and therefore reduces ‘start of life’ defects. Also, warranty provisions may provide for the supplier or contractor to bear the costs of any ‘start of life’ defects.

ElectraNet also overstated the backlog of defects in its opex forecast. It estimated the substation defects not allocated to refurbishment or replacement work programs form a backlog of about 10 months.[473] EMCa estimated the backlog to be around four to five months. EMCa's estimate was lower than ElectraNet's even though EMCa assumed a lower incoming rate of defects.[474]

The integrated asset management framework should provide downward pressure on field maintenance costs over time, because the program enables ElectraNet to better prioritise its resources. The process of comprehensively assessing asset condition will reveal the actual underlying asset condition. ElectraNet can use this information to identify priority areas for future

470 This is equivalent to a $25.3 million step change to the AER’s top-down model.
471 NER, clauses 6A.6.(c)(1)–(2).
472 ElectraNet, *Asset Management Plan*, [public version], p. 34.
473 EMCa, *ElectraNet technical review,* October 2012, p. 123, paragraph 466; p. 127, paragraph 475.
474 This estimate is based on EMCa's analysis [paragraph 466 of draft technical review] which is primarily drawn from analysis of ENET response 182, figure 5.1.

expenditure, but also areas of past expenditure that lead to inefficient outcomes. However, with no evidence of ElectraNet under-maintaining its asset base, the AER did not observe a decline in ElectraNet's high service and reliability standards. Neither did it observe significant capex nor opex overspends that may indicate the TNSP had not maintained its assets.[475]

EMCa did not find evidence that ElectraNet assessed life cycle 'correct now' versus 'correct later' engineering and/or economic options for corrective maintenance. In deciding whether ElectraNet's proposal meets the opex criteria, the AER must have regard to the opex factors, which include the extent of substitution possibilities between opex and capex.[476] It considered a prudent operator in ElectraNet's circumstances[477] could reasonably have undertaken an economic and/or engineering assessment, which would have resulted in some deferrals of corrective maintenance opex or replacement capex.

In its submission, the ECCSA discussed the relationship between routine and corrective maintenance expenditure. The AER has similar concerns, that is, that the improved routine maintenance program should lead to a quantifiable reduction in corrective maintenance expenditure over time. ECCSA found it 'difficult to accept that there are even more [routine maintenance] inspections than occurred in the 2008–13 regulatory control period as ElectraNet does not advise that it is introducing new requirements'.[478] ECCSA noted:

> increased in routine maintenance allowed in 2008–13 regulatory control period was in part to reduce the need for corrective maintenance ...[but that]... the 2008–13 regulatory control period was a relatively steady annual average cost ..for corrective maintenance which was to reduce with better condition monitoring – that was the argument for increasing routine maintenance. However, corrective maintenance is forecast to increase to an annual average cost of nearly $14m pa, a step increase of more than 50%. The ECCSA does not consider that the investment in improved condition monitoring should result in increased corrective maintenance and should have delivered a reduction; as was the argument proposed by ElectraNet in 2007.

Operational refurbishment

The AER does not accept ElectraNet's proposed operational refurbishment expenditure (the opex component) over and above the revealed cost because ElectraNet did not sufficiently demonstrate its proposed opex is a prudent and efficient step-change increase in its expenditure requirements. Operational refurbishment is also considered in the expenditure chapter and the capex chapter.

ElectraNet proposed $64.8 million for operational refurbishment as an opex category for 2013–18, but also proposed another $54.2 million for operational refurbishment as part of its capex program. The total operational refurbishment expenditure proposed for 2013–18 is thus $119.0 million, nearly three and a half times the actual operational refurbishment expenditure in 2008–13 ($35.8 million). ElectraNet's proposed operational refurbishment opex exceeds the historical cost trend by $18.1 million (36 per cent) and is an 81 per cent increase on the allowance for this opex category in the 2008–13 regulatory control period.

In particular, ElectraNet's proposal for operational refurbishment requirements–$18 million over and above its historical revealed cost requirement–was a bottom up forecast with no link to its historical costs or revealed efficiency. But in this forecast, ElectraNet identified approximately $15 million of the proposed operational refurbishment expenditure is for 'assessing asset condition (mostly for

475 A large overspend may indicate that the occurrence of high impact risk events that required urgent and unscheduled correction.
476 NER, clause 6A.6.6(e)(7).
477 NER, clause 6A.6.6(c)(2).
478 ECCSA, *Submission to ElectraNet's revenue proposal 2013–18*, August 2012, p. 33.

transmission lines) and for continuing to deploy the integrated asset management framework'.[479] The AER is concerned this definition is inconsistent with ElectraNet's opex category for operational refurbishment, but rather fits its own definition of the maintenance support cost category (which includes: 'asset condition monitoring and analysis').[480] The AER is not clear why ElectraNet included this $15 million of condition assessment expenditure as asset refurbishment and therefore does not accept this forecast meets the opex objectives, because the additional expenditure may be duplicated elsewhere in the proposal.

Furthermore, ElectraNet's opex refurbishment program is driven by needs identified through condition assessment. But, ElectraNet chose to reduce its opex refurbishment expenditure in the final two years of the 2008–13 regulatory control period and estimated this expenditure to be less than the annual regulatory allowance for 2011–12 and 2012–13. This outcome suggests ElectraNet can prudently defer some of the cost–risk tradeoffs with minimal risk impact.

Support and network operations

ElectraNet's forecast for asset management support, maintenance support, network operations and corporate support was based on a revealed costs approach, with 2011–12 as the base year. The AER found 2011–12 was not a year representative of efficient costs, and instead used 2010–11 because it better reflects efficient costs (section 5.4.2). EMCa also found 2010–11 to be an efficient base year and its adjustment of $13.3 million for support and $4.3 million for network operations reflects the change in base year from 2011–12 to 2010–11.[481]

Land tax

The AER does not accept ElectraNet's proposed forecast for land tax of $14.7 million ($2012–13) because the forecast overestimates ElectraNet's land tax requirement for the 2013–18 regulatory control period. The AER's draft decision is to provide ElectraNet with a land tax allowance of $11.8 million ($2012–13), which is a reduction of $2.9 million (land-tax is a zero based cost item in the AER's substitute forecast).

ElectraNet forecast land tax by applying the tax rate to the portfolio of existing land holdings and to its forecast of acquisitions during the 2013–18 regulatory control. In its submission, ECCSA noted the 'significant increase in land tax obligations which it assumed is related to the increase in land acquisition included in the capex forecast and noted the AER needs to evaluate this sudden increase in land acquisition and whether this program is efficient'.[482]

As discussed in attachment 4, the AER does not accept ElectraNet's land and easement acquisition forecast for the 2013–18 regulatory control period and accordingly has substituted a revised forecast for land acquisition, which is lower than proposed. Therefore the AER recalculated land tax so it is consistent with the AER's decision on ElectraNet's land and easements program.[483]

Furthermore, the AER does not accept ElectraNet's average land valuation factor of 9.5 per cent used in its land tax calculation. ElectraNet escalated the land values based on average land value growth factors derived from ABS data rather than the individual growth factors for residential (10.56 percent), commercial (7.89 per cent) and rural land (7.37 per cent). Applying the individual growth factors for each category of land, and not the average, reduces the forecast land tax.

479 EMCa, *ElectraNet technical review,* October 2012, p. 129, paragraph 482.
480 ElectraNet, *Revenue proposal*, p. 89.
481 EMCa did not consider the EBSS in this calculation.
482 ECCSA, *Submission to ElectraNet's revenue proposal 2013–18*, August 2012, p. 40.
483 The AER did this by using ElectraNet's land tax model.

Table 5.8 **Land tax allowance ($ million, 2012–13)**

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet proposal	2.5	2.7	2.9	3.2	3.4	14.7
AER draft decision	2.1	2.2	2.3	2.5	2.7	11.8

Source: AER analysis

5.4.4 Non-controllable opex

Insurance

ElectraNet proposed an insurance allowance of $15.1 million for the 2013–18 regulatory control period as non-controllable operating expenditure. The AER does not accept this forecast as the efficient cost required to meet the opex objectives because it exceeds the revealed cost trend line forecast by about $2.0 million. The AER has included insurance as a base year cost in its substitute forecast, the total amount for insurance (after escalation) in the top down forecast is $13.0 million for 2013–18 regulatory control period.

ElectraNet did not escalate base year costs for its insurance forecast, but sourced an expert estimate (from an insurance broker, Marsh Pty. Ltd) of the forecast premiums. ElectraNet reasoned this was because: 'variations in insurance premiums do not necessarily follow similar escalation profiles to other costs and are influenced by a range of factors beyond the control of ElectraNet'.[484]

The AER disagrees that insurance costs necessarily follow different escalation profiles to other costs and should therefore be excluded from the base-year assessment approach; nor does the AER accept that insurance (but not self insurance) is a non-controllable expenditure item. The AER observes the similarities between the way the Marsh report presents the drivers of the forecast insurance premium and the AER's base-year-extrapolated approach. The Marsh report identifies three drivers for changes in insurance premiums: change in exposure, inflation and market factors. The AER's base-year-extrapolated forecast provides for insurance costs in its base year and these are escalated by CPI (some insurance is included in the CPI basket) and for network growth (similar to Marsh's 'exposure'). The difference then, between the AER's base-year-extrapolated insurance and Marsh's forecast, is the market factor (the market premium).

The Marsh report estimates ElectraNet's total base premium for a number of very different lines of insurance, for example: industrial special risk, motor vehicle and corporate travel.[485] ElectraNet's proposed forecast is based on the (weighted) aggregate of its exposure across all these insurance types, but insurance is priced in a competitive market for each class of insurance. While the Marsh report does observe that the commercial property market 'now appears to be hardening' (and therefore the market premium for this insurance category has been increased in the forecast) it also observes that other insurance markets (for example, liability markets, financial lines markets, etc) have been flat for a number of years.[486] In other words, the market factor for insurance can, and does, vary from year to year and across insurance categories, but this is also true of many base year expenditure cost items.

484 ElectraNet, *Revenue proposal*, p. 107.

485 Marsh, *Premium projections (2013–14 to 2017–18) for ElectraNet*, May 2012, sets these out as Industrial Special Risks, Primary and Excess Liability, Excess Workers' Compensation, Corporate Travel, Group Personal Accident, Motor Vehicle, Marine Transit, Inpatriate Health, Directors' and Officers' Liability, Employment Practices Liability, Directors' and Officers' Supplementary Legal Expenses, Statutory Liability.

486 Marsh, *Premium projections (2013–14 to 2017–18) for ElectraNet*, May 2012, p. 14.

The AER does not find that the variability of insurance market premiums sufficient reason to exclude insurance from the base year extrapolated approach. In general, a TNSP, for any one year, is likely to have some insurance premiums costs that are higher than the base year extrapolated amount (business as usual) and some insurance premium costs that are lower. While ElectraNet's actual insurance premium payable in any one insurance category might have been lower in the base year, other insurance premium types were possibly higher. Many factors influence actual insurance market premiums in any one year in both directions (and in aggregate), so the AER considers a forecast of total opex is more likely to include estimation errors if it does not reflect of all opex incurred in a financial year. To the extent that any costs were lower (higher) than average in the base year, ElectraNet will be rewarded (penalised) through its opex EBSS incentive mechanism. In other words, ElectraNet will retain any cost reductions (increases) in its base year for a five year period. To then adjust the base year would lead to over (under) compensation.

Self insurance

ElectraNet proposed a self insurance allowance of $7.5 million for the 2013–18 regulatory control period, which included $0.69 million to self insure for bushfire liability above the commercial insurance cap.

Subsequent to ElectraNet lodging its revenue proposal, an Australian Energy Market Commission rule change gave TNSPs the ability to nominate additional pass through events in their revenue proposal.[487] ElectraNet stated that it would no longer require self insurance against the bushfire liability risk if the AER accepts its proposed insurance cap pass through event.

As the AER accepts an insurance cap event as a nominated pass through event for the 2013–18 regulatory control period (refer attachment 16), its draft decision is to reject ElectraNet's proposed self insurance allowance of $7.5 million and substitute a forecast of $6.8 million to reflect ElectraNet's reduced risk profile.[488]

Table 5.9 Self insurance allowance ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Self insurance	1.3	1.3	1.4	1.4	1.4	6.8

Source: ElectraNet, *Pass through event proposal*, August 2012, p. 18.

Network support

The AER accepts ElectraNet's proposed allowance of $41.6 million for network support for the 2013-18 regulatory control period. ElectraNet's proposal is based on a forecast of the cost of network support services contracted to be provided at Port Lincoln on the Eyre Peninsula.[489] The estimate includes both fixed and variable costs based on an existing service provider agreement. ElectraNet did not identify any other network support services that could defer capital investment during the regulatory period. The AER recognises the importance of network support as a potentially efficient means to defer or avoid network augmentation. These outcomes are beneficial to customers and consistent with the National Electricity Objective. Therefore, if ElectraNet enters an agreement with a

487 AEMC, *Rule determination, National electricity amendment (cost pass through arrangements for network service providers) rule 2012*, 2 August 2012.

488 ElectraNet, *Pass through event proposal*, August 2012, p. 15.

489 ElectraNet provided the relevant sections of the agreement in ElectraNet, *ENET190 email response to information request EMCa/035, Network support contract*, 3 July 2012, p. 27 [confidential].

network support provider after the start of the regulatory control period, and it has not received a related opex allowance, it can submit a network support pass through application to the AER.[490]

Debt raising costs

The AER accepts ElectraNet's proposed method for determining its benchmark debt raising costs allowance. Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs are a legitimate expense for a prudent service provider acting efficiently and an allowance should be provided to recover these costs.

ElectraNet proposed a total debt raising cost allowance of $6.3 million over the 2013–18 regulatory control period.[491] This allowance was calculated based on the benchmark unit rate for debt raising costs used by the AER in its recent final decision for Powerlink's electricity transmission network.[492]

To determine the total benchmark debt raising cost allowance, the AER relies on a method that was initially developed by the Allen Consulting Group (ACG).[493] Broadly, the ACG method involves two key steps:

- First, a benchmark unit rate for debt raising costs is calculated. This unit rate, expressed in basis points per annum, is determined based on estimates of:
    - the transaction costs that a prudent service provider, acting efficiently, would incur in raising debt[494]
    - the expected timing and frequency of these transaction costs[495]
    - the number of 'standard' bond issuances required over the regulatory control period to finance the benchmark debt portion of the TNSP's RAB.[496]
- Second, the debt raising cost allowance is determined in the post-tax revenue model as the product of the benchmark unit rate and the debt portion of the TNSP's RAB.[497]

The AER has periodically updated the inputs into the ACG method with more recent market data. Specifically, the AER has updated the value of expected transaction costs, the assumed standard bond size, and the WACC applied in deriving the benchmark unit rate.[498] Further, the AER will update

490 NER, clause 6A.7.2; The AER recently published a procedural guideline to help TNSPs apply for network support pass through: AER, *Procedural guideline for preparing a transmission network support pass through application,* June 2011 www.aer.gov.au/content/index.phtml/itemId/742680.

491 ElectraNet, *Revenue proposal,* p. 149.

492 Further details regarding the AER's approach for calculating debt raising costs are outlined in the AER's final decision for Powerlink. AER, *Final decision Powerlink Transmission determination 2012–13 to 2016–17*, April 2012.

493 ACG, *Debt and equity raising transaction costs—Final Report*, December 2004.

494 These transaction costs include gross underwriting fees; legal and roadshow costs; maintaining a company credit rating; establishing an issuance credit rating; and registry fees (both at commencement and ongoing).

495 The ACG method considers that transaction costs can be incurred up-front or annually, and per debt issuance or per company. The AER amortises up-front costs (for example, underwriting fees) using the relevant nominal vanilla WACC over a ten year amortisation period.

496 The AER assumes that the size of a 'standard' bond issue is currently $250 million. The standard bond issue is relevant to transaction costs that are independent of the number of debt issuances (for example, maintaining a company credit rating). In particular, the benchmark unit rate is inversely related to the number of bond issuances required by a TNSP over the regulatory control period. That is, as the number of bond issuances increases, the benchmark unit rate (for debt raising costs) per issuance will decrease.

497 The debt portion of the TNSPs RAB is calculated based on the benchmark gearing ratio determined in the WACC review. That is, for the purpose of this draft decision, the debt component of the RAB is assumed to equal 60 per cent of the total RAB.

498 The revised transaction costs and standard bond size are consistent with those determined in the AER's final decision for Powerlink. These updates reflect analysis undertaken by PwC, which was commissioned by Powerlink. PwC, *Powerlink Queensland 2013–2017 Revenue proposal: Appendix K—Debt and equity raising costs,* April 2011.

the benchmark debt raising cost allowance for the final decision based on the debt component of the RAB and WACC determined at that time.

For this draft decision, the AER has updated ElectraNet's proposed benchmark unit rate for debt raising costs to reflect the indicative WACC. The AER has also updated the benchmark unit rate to reflect the number of 'standard' bond issuances required over the 2013–18 regulatory control period to finance the debt portion of ElectraNet's RAB. This has resulted in a benchmark unit rate for debt raising costs of 9.0 basis points per annum. Accordingly, the AER has determined a benchmark debt raising cost allowance of $5.8 million ($2012–13) for ElectraNet as shown in Table 5.10.

Table 5.10 AER draft decision on debt raising costs ($ million, 2012–13)

Unit rate	2013–14	2014–15	2015–16	2016–17	2017–18	Total
9.0 basis points per year	1.1	1.1	1.2	1.2	1.2	5.8

Source: AER analysis.

The AER considers this method provides estimates of debt raising costs that would be incurred by a prudent service provider, acting efficiently. Most notably, this is because the AER's approach:

- identifies the types of transaction costs that a prudent service provider acting efficiently would incur in raising debt, and
- quantifies the level of these costs (taking into account the specific circumstances of the service provider) with reference to market rates for the relevant services.

5.5 Revisions

The AER requires the following revisions to make the ElectraNet's revenue proposal reasonably reflect the opex objectives and opex criteria:

Revision 5.1: make all necessary amendments to reflect the AER’s draft decision on conforming operating expenditure for the 2013–18 regulatory control period in Table 5.1 and table 5.2.

6 Cost of capital

As part of making a determination on the annual building block revenue requirement for a transmission network service provider (TNSP), the Australian Energy Regulator (AER) is required to make a decision on the return on capital building block.[499] The return on capital building block is calculated as the product of the cost of capital (or rate of return) and the value of the regulatory asset base (RAB).

This attachment sets out the AER's determination of the cost of capital component to apply to ElectraNet over the 2013–18 regulatory control period. Consistent with the National Electricity Rules (NER), the cost of capital is measured as the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the transmission business.[500] It must be calculated as a nominal post-tax weighted average cost of capital (WACC).[501]

6.1 Draft decision

The AER accepts ElectraNet's proposed method for determining the WACC, including ElectraNet's proposed averaging period.[502] However, the AER determined an indicative WACC of 7.11 per cent, as set out in Table 6.1. The AER's draft decision reflects market based parameters—the nominal risk free rate and the debt risk premium (DRP)—estimated over an indicative averaging period.[503] The AER will update these parameters for its final decision, based on the averaging period proposed by ElectraNet.

Table 6.1 AER's draft decision on WACC parameters

Parameter	AER draft decision
Nominal risk free rate	3.03%
Equity beta	0.8
Market risk premium	6.50%
Debt risk premium	3.34%
Gearing level	60%
Inflation forecast	2.50%
Gamma	0.65
Nominal post-tax cost of equity	8.23%
Nominal pre-tax cost of debt	6.37%
Nominal vanilla WACC	7.11%

Source: AER analysis.

499 NER, clause 6A.5.4(a)(2).
500 NER, clause 6A.6.2(b).
501 NER, clause 6A.6.2(b).
502 Consistent with the NER, ElectraNet's proposed averaging period will remain confidential until the expiration of the agreed period.
503 Specifically, the AER's draft decision is based on a 20 business day indicative averaging period, from 24 September to 19 October 2012. ElectraNet's proposed rate of return method, if also applied to market data from the AER's indicative averaging period, would result in a proposed rate of 7.14 per cent.

6.2 ElectraNet's proposal

ElectraNet proposed a nominal vanilla WACC of 7.73 per cent, based on market data from May 2012.[504] This WACC reflects the parameters shown in Table 6.2, and discussed below.

Table 6.2 ElectraNet's proposed WACC parameters

Parameter	ElectraNet proposal
Nominal risk free rate	3.26%
Equity beta	0.8
Market risk premium	6.50%
Debt risk premium	3.98%
Gearing level	60%
Inflation forecast	2.50%
Gamma	0.65
Nominal post-tax cost of equity	8.46%
Nominal pre-tax cost of debt	7.24%
Nominal vanilla WACC	7.73%

Source: ElectraNet, *Revenue proposal*, p. 129.

In calculating its proposed WACC, ElectraNet applied the equity beta, market risk premium (MRP) and the level of gearing determined by the AER in the 2009 review of the WACC parameters. Similarly, as part of estimating its tax allowance, ElectraNet proposed to apply the gamma value specified in the WACC review.

ElectraNet's method for determining the risk free rate is also consistent with that stated in the WACC review. That is, the nominal risk free rate reflects the annualised yields on 10 year Commonwealth Government securities (CGS) based on an averaging period as close as practically possible to the start of the regulatory control period. Given ElectraNet's nominated averaging period is in the future, the risk free rate in the TNSP's revenue proposal is based on an indicative averaging period.

To determine the debt risk premium (DRP), ElectraNet commissioned a report by PriceWaterhouseCoopers (PwC).[505] PwC estimated the DRP by extrapolating Bloomberg's seven year BBB rated fair value curve to an equivalent 10 year term. The extrapolation approach is based on a pair bonds analysis.[506] This approach is consistent with that previously developed by PwC and relied on by the AER in recent decisions.[507]

504 Specifically, ElectraNet's proposed WACC reflects a 10 business day indicative averaging period, from 9 May to 22 May 2012.

505 PwC, *ElectraNet: estimating the benchmark debt risk premium*, May 2012.

506 Specifically, the Bloomberg seven year BBB fair value curve is extrapolated using the average annual increment observed across pairs of bonds of differing maturities issued by the same company.

507 For example, see: AER, *Draft decision: APA GasNet Australia (Operations) Pty Ltd, access arrangement draft decision,* September 2012.

ElectraNet stated its proposed inflation forecast is consistent with the AER's previously adopted approach to estimating the expected inflation rate.[508]

6.3 Assessment approach

This section considers:

- the requirements of the National Electricity Law (NEL) and NER on the rate of return
- the determination of specific parameters.

6.3.1 Requirements of the NEL and NER on the rate of return

The NER requires the AER to apply a rate of return based on the nominal vanilla WACC formulation.[509] In calculating the nominal vanilla WACC, the AER must:

- apply the capital asset pricing model (CAPM) to determine the return on equity[510]
- adopt the parameter values, methods and credit rating determined in the WACC review.[511]

ElectraNet submitted its revenue proposal after the completion of the 2009 WACC review. The relevant values, methods and credit rating, therefore, are those determined in that review (Table 6.3).

Table 6.3 Values, method and credit rating determined in 2009 WACC review

Parameter	WACC review
Nominal risk free rate	Annualised yield on 10 year CGS based on agreed averaging period as close as practically possible to the start of the regulatory control period
Equity beta	0.8
Market risk premium	6.50%
Credit rating	BBB+
Gearing level	60%
Assumed utilisation of imputation credits (gamma)	0.65

Source: AER, *Statement of the revised WACC parameters (transmission)*, May 2009, p. 6.

6.3.2 Determination of specific parameters

To determine the WACC applicable at the time of any given determination, the AER updates values for the DRP, nominal risk free rate and inflation based on prevailing market data. This market data reflects an averaging period as close as practically possible to the start of the regulatory control period. For this draft decision, the AER used an indicative 20 day averaging period, ending 19 October 2012.

508 ElectraNet, *Revenue proposal*, p. 128.
509 NER, clause 6A.6.2(b).
510 The CAPM is a well known and widely used model. It specifies a relationship between the expected return of a risky asset (in terms of uncertainty over future outcomes) and the level of systematic (non-diversifiable) risk.
511 NER, clause 6A.6.2(h).

Debt risk premium

The DRP is the margin above the nominal risk free rate that a debt holder would require to invest in a benchmark efficient service provider. Combined with the nominal risk free rate, the DRP represents the return on debt and is an input for calculating the WACC. The AER's assessment approach for this draft decision is consistent with that adopted in the AER's recent final decision for the Roma to Brisbane Pipeline.[512] That is, the AER estimated the DRP using:

- an appropriate benchmark
- a method that conforms to these benchmark parameters.

Benchmark

The AER adopted a 10 year Australian corporate bond with a BBB+ credit rating as the benchmark for estimating the DRP.[513] The term of this benchmark provides internal consistency with the method for calculating the nominal risk free rate determined in the WACC review.

Method used to estimate the DRP

To estimate the 10 year DRP for this draft decision, the AER used:

- the Bloomberg BBB rated fair value curve, to estimate the (base) seven year DRP
- the average annual increment observed across bonds of differing maturities issued by the same company, to extrapolate the seven year DRP estimate to 10 years.

Nominal risk free rate

The risk free rate measures the return that an investor would expect from an asset with zero volatility and zero default risk. The yield on long term CGS is often used as a proxy for the risk free rate because the risk of government default on interest and debt repayments is considered to be low.

In the CAPM framework, all information used for deriving the rate of return should be as current as possible, to achieve an unbiased forward looking rate. Using the on-the-day rate may be theoretically correct because it represents the latest available information. This approach, however, exposes the TNSP and customers to daily volatility. For this reason, an averaging period approach is used to minimise volatility in observed bond yields.

Expected inflation rate

The expected inflation rate is not a parameter relevant to the determination of the WACC.[514] However, it is used in the post tax revenue model (PTRM)—for example, to index the RAB—and is an implicit component of the nominal risk free rate. For this reason, this attachment discusses the AER's determination of the expected inflation rate.

The AER's approach to estimating inflation is consistent with that used in previous regulatory decisions. This method involves:

512 AER, *Final decision: APT Petroleum Pipeline Pty Ltd, Access arrangement final decision, Roma to Brisbane Pipeline 2012–13 to 2016–17*, August 2012.
513 NER, clause 6A.6.2(e).
514 The WACC formulation is based on nominal parameters and does not incorporate an explicit inflation rate parameter.

- taking a geometric average of forecast inflation for each of the next 10 years (consistent with using a 10 year term for the risk free rate and other WACC parameters)
- adopting the Reserve Bank of Australia's (RBA) headline inflation forecasts from the latest RBA Statement on Monetary Policy, for as many future years as the RBA publishes inflation forecasts
- adopting the mid-point of the RBA's inflation target (2.5 per cent) for the remaining future years (out to year 10).

6.4 Reasons for draft decision

ElectraNet's proposed method for determining the WACC adopted the values, methods and credit rating determined in the WACC review—specifically, the equity beta, the MRP, the level of gearing and the value of the assumed utilisation of imputation credits (gamma).[515] The AER, therefore, accepts ElectraNet's proposed values for these parameters (section 6.4.1).

In establishing the WACC, the AER also accepts ElectraNet's proposed method for determining the DRP, the nominal risk free rate and inflation forecasts. The AER's reasons are discussed in sections 6.4.2, 6.4.3 and 6.4.4.

6.4.1 Parameters determined in the WACC review

In the WACC review, the AER specified the following parameter values:

- Equity beta of 0.8—The equity beta provides a measure of the 'riskiness' of an asset's return compared with the return on the entire market. The equity beta reflects the asset's exposure to non-diversifiable (systematic) risk, which is the only form of risk that requires compensation under the CAPM. An equity beta of 1.0 implies the firm's return has the same level of systematic risk as that of the overall market. An equity beta of less than 1.0 implies the firm's return is less sensitive to systematic risk than is the overall market, and vice versa.
- MRP of 6.5 per cent—The MRP is the expected return over the risk free rate that investors require to invest in a well diversified portfolio of risky assets. It represents the risk premium that investors in such a portfolio can expect to earn for bearing only non-diversifiable (systematic) risk. The MRP is common to all assets in the economy and not specific to an individual asset or business.
- Gearing level of 60 per cent—Gearing is defined as the ratio of the value of debt to total capital (that is, both debt and equity). It is used to weight the costs of debt and equity when formulating the WACC.
- Gamma of 0.65—Under the Australian imputation tax system, domestic investors receive a credit for tax paid at the company level (an imputation credit, or gamma), which offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received.

As outlined, the AER accepts ElectraNet's proposed values for these parameters, which are consistent with those determined in the WACC review.[516]

[515] The assumed utilisation of imputation credits (gamma) affects the corporate income tax building block allowance. Although gamma is not directly included in the determination of the WACC, it was determined in the WACC review.

[516] AER, *Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission)*, May 2009, p. 6.

6.4.2 Debt risk premium

The AER accepts, in principle, ElectraNet's proposed benchmark and method for determining the DRP. The AER, however, updated ElectraNet's proposed DRP to 3.34 per cent, to reflect the indicative averaging period used throughout this draft decision.[517] The AER will again update this value for its final decision, based on ElectraNet's final averaging period.

Specifically, the AER accepts ElectraNet's proposed DRP benchmark based on an Australian corporate fixed rate bond issue with a term to maturity of 10 years and a BBB+ credit rating.[518] The AER adopted this benchmark assumption in previous electricity decisions.[519] Moreover, it considers the term to maturity and credit rating are two primary factors that reflect the risks involved in providing reference services.[520] The 10 year term for the cost of debt also provides internal consistency with the use of a 10 year risk free rate.

Further, the AER accepts ElectraNet's proposed approach to establishing the DRP. In particular, it accepts ElectraNet's proposal to estimate the benchmark DRP solely on the Bloomberg BBB fair value curve. Notwithstanding the AER's previous concerns with the Bloomberg fair value curve, the AER is mindful of the Australian Competition Tribunal's recommendation to complete a public consultation process before considering any alternative methods.[521]

The AER also accepts ElectraNet's proposed method to extrapolate the Bloomberg BBB fair value curve from seven to 10 years, based on the PwC analysis of paired bonds.[522] The AER, however, does not consider PwC correctly applied this extrapolation approach. PwC's method extrapolated the Bloomberg seven year BBB fair value curve using the average annual increment observed across pairs of bonds of differing maturities issued by the same company. PwC's criteria for selecting the sample of paired bonds included that:

- the paired bonds were part of the wider sample that PwC used to conduct its broader econometric analysis
- the shorter dated bond (of the pair) had a remaining term to maturity closest to seven years.[523]

Based on PwC's selection criteria, the AER cannot reconcile the inclusion of the paired Telstra bonds in PwC's extrapolation sample. Specifically, Telstra bonds have an A credit rating by Standard and Poor's. Among other characteristics, the broader econometric sample used by PwC (of which the paired bonds must be a subset) included only bonds with a BBB, BBB+ or A– credit rating by Standard and Poor's.[524]

Additionally, PwC's extrapolation sample included a pair of fixed rate Stockland bonds maturing in 2015 and 2020. However, a fixed rate Stockland bond matching all of PwC's selection criteria exists that matures in 2016. The AER considers the correct application of PwC's selection criteria requires the 2016 bond to be used (instead of the bond maturing in 2015).

517 This estimate also reflects the AER's amendment to the bond sample used to extrapolate Bloomberg's seven year BBB rated fair value curve.
518 ElectraNet, *Revenue proposal*, pp. 124–129.
519 For example, see: AER, *Final decision, Powerlink transmission determination 2012–13 to 2016–17*, April 2012.
520 Other factors—for example, industry type—may also be relevant in determining the level of risk involved in providing reference services.
521 Australian Competition Tribunal, *Application by Envestra Limited (No 2)* [2012] ACompT 3, 11 January 2012, paragraphs 95, 118, 120–1; see also Australian Competition Tribunal, *Application by APT Allgas Energy Ltd* [2012] ACompT 5, 11 January 2012.
522 Seven years is the maximum term currently published for the Bloomberg BBB fair value curve.
523 PwC, *ElectraNet: estimating the benchmark debt risk premium*, May 2012, p. 22.
524 PwC, *ElectraNet: estimating the benchmark debt risk premium*, May 2012, p. 13.

For this draft decision, therefore, the AER excluded the Telstra bonds from the extrapolation sample. It also updated PwC's analysis to reflect the spread between the pair of Stockland bonds maturing in 2016 and 2020. It will consider including these bonds for the final decision if ElectraNet substantiates its inclusion. The AER considers excluding the Telstra bonds and amending the Stockland pair is consistent with a benchmark DRP that reflects the risks involved in providing reference services.

In assessing ElectraNet's proposal, the AER also considered submissions from the Energy Consumers Coalition of South Australia (ECCSA) and the Energy Users Association of Australia (EUAA).[525] The ECCSA stated the AER's previous approach to determining the DRP cannot be demonstrated to produce an efficient outcome. Further, it presented average debt premiums (based on annual reports) for four privately owned electricity and gas network firms operating in Victoria. The EUAA submitted the AER should not rely on the Bloomberg fair value curve for determining the cost of debt.[526]

The AER considers the ECCSA's analysis of annual report data is flawed. Most notably, it is unclear whether the average term of the debt referenced by the ECCSA corresponds to the benchmark term adopted by the AER. In this context, it is inappropriate to calculate the DRP for an entire portfolio with reference to only the 10 year risk free rate.[527]

The EUAA's submission presented analysis that incorrectly characterised key facts. Most notably, the AER did not adopt a simple average of bonds for the Powerlink final decision.[528] The AER also considers a number of the inherent problems with the Bloomberg fair value curve estimates—for example, limited executed trading data and the need for extrapolation—are likely be present in any alternative approaches.

Notwithstanding the above, the issues raised by the ECCSA and EUAA warrant consideration—for example, the current DRP method does not reflect the full spectrum of debt options used by NSPs, and the Bloomberg method lacks transparency. These issues are consistent with the Australian Competition Tribunal's recommendation to undertake a public consultation process before selecting an alternative DRP method.[529] For these reasons, the AER commenced an internal review into alternatives to the Bloomberg fair value curve. It will advise of public consultation on the development of an alternative.

6.4.3 Nominal risk free rate

The AER accepts ElectraNet's proposed averaging period to calculate the nominal risk free rate. It also accepts ElectraNet's request to keep the averaging period confidential until the expiration of that period.[530] For this draft decision, the AER used an indicative 20 day averaging period ending 19 October 2012, which results in a risk free rate of 3.03 per cent (effective annual compounding rate).[531] The AER will update the risk free rate, based on the agreed averaging period, at the time of its final decision.[532]

525 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application, A response by ECCSA*, August 2012. EUAA, *Submission on ElectraNet's revenue proposal for 2013–18*, August 2012.

526 EUAA, *Submission on ElectraNet's revenue proposal for 2013–18*, August 2012, pp. 19–20.

527 For example, the DRP for seven year debt should be determined with reference to the seven year risk free rate.

528 The AER adopted the bond sample approach for only the Powerlink draft decision. It detailed the reasons for departing from this approach in its final decision for Powerlink. AER, *Final decision, Powerlink transmission determination 2012–13 to 2016–17*, April 2012.

529 Australian Competition Tribunal, *Application by Envestra Limited (No 2)* [2012] ACompT 3, 11 January 2012, paragraphs 95, 118, 120–1; see also Australian Competition Tribunal, *Application by APT Allgas Energy Ltd* [2012] ACompT 5, 11 January 2012.

530 NER, clause 6A.6.2(c)(2)(iii).

531 CGS yields are sourced from the RBA: www.rba.gov.au/statistics/tables/xls/f16.xls.

532 It will use the same averaging period to calculate the DRP.

6.4.4 Expected inflation rate

The AER accepts ElectraNet's proposed method for forecasting inflation. This approach is consistent with that previously adopted by the AER (and outlined in section 6.3.2). The AER, however, updated ElectraNet's proposed inflation estimate to reflect the latest RBA forecasts. These estimates, shown in Table 6.4, result in an inflation forecast of 2.50 per cent per annum.[533] The AER will again update its inflation estimate for the final decision.

Table 6.4 AER draft decision on inflation forecast (per cent)

	2013–14	2014–15	2015–16 to 2022–23	Geometric average
Forecast inflation	2.50[a]	2.50[b]	2.50	2.50

Source: RBA, *Statement on Monetary Policy*, August 2012.
(a) The RBA published a range of 2.0–3.0 per cent for its 2013–2014 forecast of inflation. The AER has selected the mid-point of 2.50 per cent for the purposes of this decision.
(b) The AER expects the RBA to publish a 2014–15 inflation estimate prior to the AER's final decision. For this decision, the AER has adopted the mid-point of the RBA's inflation target.

6.4.5 Reasonableness checks on the overall rate of return

In addition to the consideration of individual WACC parameters, recent AER decisions have included analysis of available estimates of the overall rate of return.[534] For this decision, however, the AER has largely accepted ElectraNet's proposed method for estimating the rate of return. As such, the difference between ElectraNet's proposed WACC and the AER's draft decision is relatively minor.[535] This decision, therefore, does not include analysis of overall rate of return estimates.

6.5 Revisions

Revision 6.1: the AER has determined a WACC of 7.11 per cent for ElectraNet, as set out in Table 6.1.

533 This estimate is identical to that proposed by ElectraNet. This is because the RBA's inflation forecast for 2013–14 has not changed between its May and August monetary policy statements.

534 For example, this included analysis of: assets sales; trading multiples; broker WACC estimates; recent decisions by other regulators; the relationship between the cost of equity and the cost of debt.

535 If ElectraNet's proposed method is applied to the AER's indicative averaging period, the difference between ElectraNet's and the AER's WACC is only 3 basis points.

7 Regulatory asset base

The AER is required to determine ElectraNet's regulatory asset base (RAB) for the 2013–18 regulatory control period.[536] Setting the RAB provides the foundation for determining ElectraNet's revenue requirement. The opening RAB for each regulatory year is used to determine the return of capital (regulatory depreciation) and return on capital building block allowances, which comprise about 69 per cent of ElectraNet's forecast total revenue.[537]

This attachment presents the AER's draft decision on ElectraNet's opening RAB at the commencement of the 2013–18 regulatory control period and the forecast RAB during the 2013–18 regulatory control period.[538]

7.1 Draft decision

The AER does not accept ElectraNet's proposed opening RAB of $2099.9 million at 1 July 2013, and determined an opening RAB of $2077.8 million. The AER's draft decision represents a reduction of $22.1 million (or 1.1 per cent) on ElectraNet's proposal, made for the following reasons:

- ElectraNet's proposed opening RAB at 1 July 2008 for the 'Substation primary plant' and the 'Accelerated depreciation' asset classes are inconsistent with the values in the approved post-tax revenue model (PTRM) for the 2008–13 regulatory control period. The AER amended these values in the proposed asset base roll forward model (RFM) so they are consistent with the approved values.
- The AER adjusted the proposed actual capex in the 2008–13 regulatory control period to account for movements in provisions.
- The AER identified and corrected several other input errors in the proposed RFM, including the consumer price index (CPI), actual capex and actual asset disposal inputs.

The AER forecasts that ElectraNet's closing RAB will be $2560.0 million by 30 June 2018, which represents a 10.5 per cent reduction in ElectraNet's proposed closing RAB. The main reasons for this reduction are the AER's adjustments to:

- the opening RAB at 1 July 2013 (section 7.4.1)
- forecast capex (attachment 4)
- forecast depreciation (attachment 8).

Table 7.1 sets out the AER's draft decision on the roll forward of ElectraNet's RAB during the 2008–13 regulatory control period and the opening RAB at the start of the 2013–18 regulatory control period. Table 7.2 sets out the AER's draft decision on ElectraNet's forecast RAB during the 2013–18 regulatory control period.

536 NER, clause 6A.6.1.
537 ElectraNet, *Revenue proposal*, p. 151.
538 NER, clause 6A.6.1.

Table 7.1 AER's draft decision on ElectraNet's RAB for the 2008–13 regulatory control period ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12[a]	2012–13[b]
Opening RAB	1311.8	1390.6	1493.6	1723.9	1872.9
Capital expenditure[c]	101.5	122.8	243.9	188.5	229.4
CPI indexation on opening RAB	32.4	40.2	49.8	27.3	56.2
Straight-line depreciation[d]	–55.0	–60.0	–63.3	–66.7	–73.9
Closing RAB as at 30 June	1390.7	1493.6	1723.9	1872.9	2084.6
Difference between forecast and actual capex (1 July 2007 to 30 June 2008)					–0.4
Return on difference for 2007–08 capex					–0.2
Difference between forecast and actual assets under construction (2007–08)					–3.7
Return on difference for 2007–08 assets under construction					–2.5
Opening RAB as at 1 July 2013					2077.8

(a) Based on estimated capex. The AER will update the asset base roll forward for actual capex at the time of its final decision.
(b) Based on estimated capex and forecast inflation. The AER will update the asset base roll forward for actual CPI at the time of its final decision. However, it will update for actual capex at the next reset.
(c) As incurred, net of disposals, and adjusted for actual CPI and weighted average cost of capital (WACC).
(d) Adjusted for actual CPI. Based on as-commissioned capex.
Source: AER analysis

Table 7.2 AER's draft decision on ElectraNet's RAB for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18
Opening RAB	2077.8	2239.8	2333.1	2440.6	2528.4
Capital expenditure[a]	194.6	130.8	157.2	139.8	87.8
Inflation indexation on opening RAB	51.9	56.0	58.3	61.0	63.2
Straight-line depreciation[b]	–84.6	–93.5	–108.0	–113.1	–119.4
Closing RAB	2239.8	2333.1	2440.6	2528.4	2560.0

a) As incurred, and net of disposals. In accordance with the timing assumptions of the PTRM, the capex includes a half-WACC allowance to compensate for the six months period before capex is added to the RAB for revenue modelling purposes.
(b) Based on as-commissioned capex.
Source: AER analysis

7.2 ElectraNet's proposal

ElectraNet proposed an opening RAB of $1311.8 million as at 1 July 2008. It used the AER's RFM to roll forward its asset base and establish its proposed opening RAB of $2099.9 million ($ nominal) as at 1 July 2013.[539] ElectraNet proposed a closing RAB of $2860.7 million ($ nominal) as at 30 June 2018, which reflects its forecast capex, inflation and depreciation over the 2013–18 regulatory control period.[540]

Table 7.3 and Table 7.4 present ElectraNet's proposed roll forward of the RAB during the 2008–13 regulatory control period and the 2013–18 regulatory control period respectively.

Table 7.3 ElectraNet's proposed RAB for the 2008–13 regulatory control period ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13
Opening RAB	1311.8	1394.7	1501.9	1735.6	1888.7
Capital expenditure[a]	102.4	123.8	243.7	189.0	230.4
CPI indexation on opening RAB	32.4	40.3	50.1	27.5	56.7
Straight-line depreciation[b]	–51.9	–56.9	–60.1	–63.4	–70.7
Closing RAB	1394.7	1501.9	1735.6	1888.7	2105.1
Difference between forecast and actual capex (2007–08)					0.63
Return on difference for 2007–08 capex					0.42
Difference between forecast and actual assets under construction (2007–08)					–3.73
Return on difference for assets under construction					–2.46
Closing RAB as at 30 June 2013					2099.9

(a) As incurred, net of disposals, and adjusted for actual CPI and WACC.
(b) Adjusted for actual CPI. Based on as-commissioned capex.
Source: ElectraNet, *Proposed RFM*, 31 May 2012.

539 ElectraNet, *Revenue proposal*, p. 119.
540 ElectraNet, *Revenue proposal*, p. 148.

Table 7.4 ElectraNet's proposed RAB for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18
Opening RAB	2099.9	2295.6	2459.3	2645.2	2803.2
Capital expenditure[a]	230.8	203.0	236.3	209.3	115.0
Inflation indexation on opening RAB	52.5	57.4	61.5	66.1	70.1
Straight-line depreciation[b]	–87.6	–96.7	–111.9	–117.5	–127.5
Closing RAB	2295.6	2459.3	2645.2	2803.2	2860.7

(a) As incurred, and net of disposals.
(b) Based on as-commissioned capex.
Source: ElectraNet, *Proposed PTRM*, 31 May 2012.

7.3 Assessment approach

The AER is required to roll forward a TNSP's RAB during the current regulatory control period to establish an opening RAB for the next regulatory control period.[541] The RAB value can be adjusted for any differences in the forecast and actual capex and disposals. It may also be adjusted to reflect any changes in the use of the assets, with the RAB to include only assets used to provide prescribed transmission services.[542]

To determine the opening RAB for a transmission determination, the AER developed an asset base RFM in accordance with the requirements of the NER.[543] A TNSP must use the AER's RFM in preparing its revenue proposal. The RFM rolls forward the TNSP's RAB from the beginning of the final year of the previous regulatory control period, through the current regulatory control period, to the beginning of the next regulatory control period. The roll forward occurs for each regulatory year by:

- adding an inflation (indexation) adjustment for the relevant year. This adjustment must be consistent with the inflation factor used in the annual indexation of the maximum allowed revenue (MAR).[544]
- adding capex incurred for the relevant regulatory year.[545] Actual as-incurred capex must be used when available. However, an estimated capex is typically required for the final year of the regulatory control period. This estimated capex is then updated for actual capex at the next determination. The AER will check actual capex amounts against audited regulatory accounts data.
- subtracting depreciation for the relevant year. Depreciation based on actual capex is used to roll forward the RAB.[546]
- subtracting any disposals for the relevant year.[547] The AER will check these amounts against audited regulatory accounts data.

541 NER, clause S6A.2.1(f).
542 NER, clause S6A.2.1(f)(8).
543 NER, clause 6A.6.1(b).
544 NER, clause 6A.6.1(e)(3).
545 NER, clause S6A.2.1(f)(4).
546 NER, clause S6A.2.1(f)(5).

These annual adjustments give the closing RAB for a particular regulatory year, which then becomes the opening RAB for the subsequent regulatory year. Through this process the RFM rolls forward the RAB to the end of the current regulatory control period. The PTRM for the next regulatory control period generally adopts the same roll forward approach as the RFM for establishing the forecast RAB, although the adjustments to the RAB are based on forecasts, rather than actual amounts.

7.4 Reasons for draft decision

The AER does not accept ElectraNet's proposed opening RAB at 1 July 2013. It reduced ElectraNet's proposed opening RAB at 1 July 2013 by $22.1 million (or 1.1 per cent), for the following reasons:

- The AER adjusted the opening RAB value at 1 July 2007 for the 'Substation primary plant' and the 'Accelerated depreciation' asset classes in the proposed RFM. The AER's amended values are consistent with the values in the approved PTRM for the 2008–13 regulatory control period.
- The AER corrected several other input errors in the proposed RFM, and reversed the movements in provisions during the 2008–13 regulatory control period.

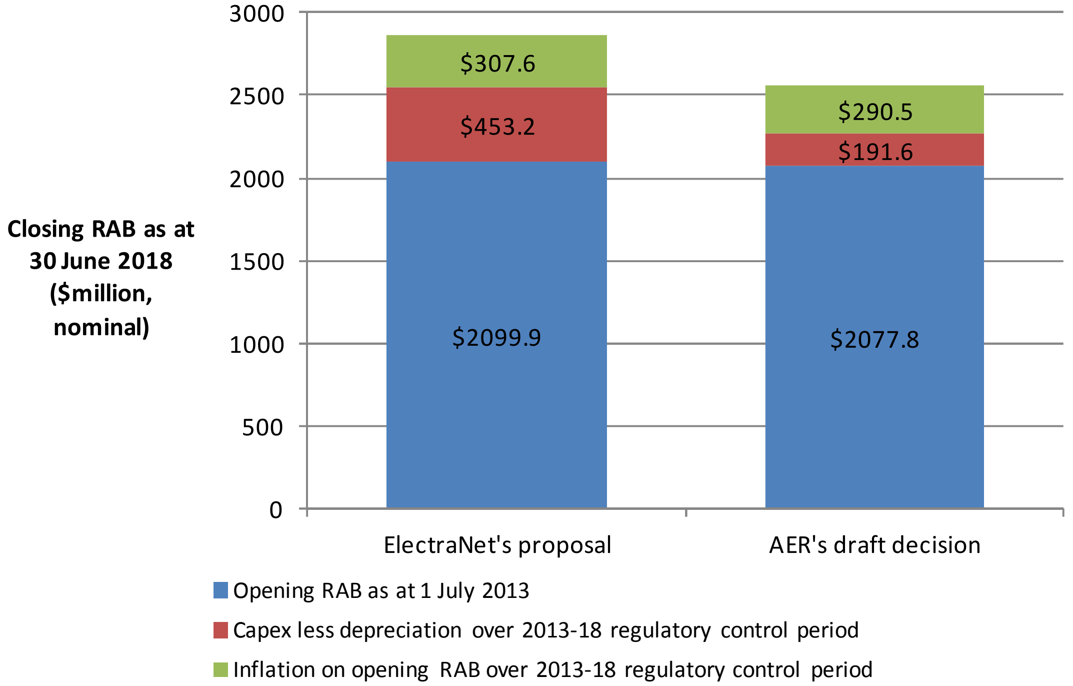
The AER forecasts ElectraNet's RAB will be $2560.0 million by 30 June 2018, which represents a 10.5 per cent reduction on the proposed closing RAB as at 30 June 2018 (see Figure 7.1). The main reasons for this reduction are the AER's adjustments to:

- the opening RAB as at 1 July 2013 (section 7.4.1)
- forecast capex (attachment 4)
- forecast depreciation (attachment 8).

Figure 7.2 shows the AER's draft decision on the opening RAB over the 2008–13 regulatory control period and forecast opening RAB over the 2013–18 regulatory control period, and ElectraNet's proposal on these values.

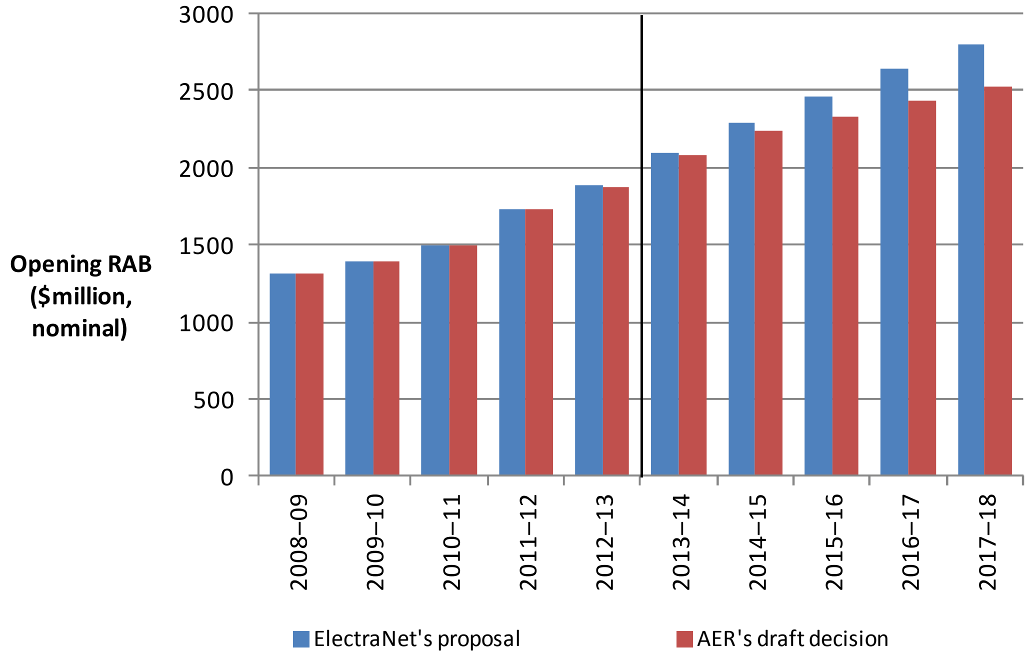
[547] NER, clause S6A.2.1(f)(6).

Figure 7.1 ElectraNet's closing RAB at the end of the 2013–18 regulatory control period ($ million, nominal)



Source: ElectraNet, *Proposed PTRM*, ENET077, May 2012; AER analysis.

Figure 7.2 ElectraNet's opening RAB over the 2008–13 and 2013–18 regulatory control period ($ million, nominal)



Source: ElectraNet, *Proposed PTRM*, ENET077, May 2012; ElectraNet, *Proposed RFM*, ENET041, May 2012; AER analysis.

7.4.1 Opening RAB at 1 July 2013

The AER does not accept ElectraNet's proposed opening RAB as at 1 July 2013 and reduced it by $22.1 million (or 1.1 per cent). This section outlines the reasons for the AER's amendments.

Opening RAB at 1 July 2008

The AER accepts ElectraNet's proposed total opening RAB as at 1 July 2008 of $1311.8 million ($ nominal), because this total value is consistent with the approved opening RAB at 1 July 2008 set by the Australian Competition Tribunal.[548] However, the opening RAB as at 1 July 2008 for the 'Substation primary plant' and the 'Accelerated depreciation' asset classes in the proposed RFM are inconsistent with the approved values for these asset classes.[549]

The AER considers the opening RAB values as at 1 July 2008 for each asset class must be consistent with the values in the approved PTRM for the 2008–13 regulatory control period. This consistency is to ensure the actual depreciation of the RAB for each asset class is calculated using the corresponding rates and methods approved for that asset class in the transmission determination for that regulatory control period.[550]

In the 2008 decision, the AER allowed $17.4 million of the 'Substation primary plant' asset value to be fully depreciated in the 2008–13 regulatory control period. However, ElectraNet's proposed RFM does not reflect this approved accelerated depreciation amount. For this reason, the AER moved $17.4 million of the opening RAB value from the ‘Substation primary plant’ asset class to the ‘Accelerated depreciation’ asset class in the proposed RFM. The AER's amended opening RAB values as at 1 July 2008 by asset class are consistent with the values in the approved PTRM for the 2008–13 regulatory control period.

This amendment, which accounts for the approved accelerated depreciation of 'Substation primary plant', reduces ElectraNet’s proposed opening RAB as at 1 July 2013 by $17.4 million (or 0.8 per cent).

Reversal of movements in provisions

ElectraNet's proposed actual capex for 2007–08 to 2012–13 included capitalised provisions. Provisions are expenditures that ElectraNet has recorded for anticipated future payments, but not yet paid out (incurred). Examples of provisions include environmental provisions, superannuation and other employee entitlements such as annual leave and long service leave.

The NER requires ElectraNet's opening RAB at 1 July 2008 to be increased by the amount of all capex incurred during the 2008–13 regulatory control period.[551] The AER considers capitalised provisions should not be included in the RAB as capex, because ElectraNet has not yet paid out (incurred) the expenses to which the provisions relate. For this reason, it adjusted ElectraNet's actual capex for 2007-08 to 2012-13 in the RFM, to reverse the movements in capitalised provisions during the 2008–13 regulatory control period. These amendments further reduce ElectraNet's proposed opening RAB at 1 July 2013 by about $3.2 million (or 0.2 per cent).

548 AER, *Statement on updates for ElectraNet transmission determination 2008–13*, February 2009, p. 1.

549 AER, *Post merits review final decision: PTRM for ElectraNet for the 2008–13 regulatory control period*, 'Input' sheet.

550 NER, S6A.2.1(f)(5).

551 NER, S6A.2.1(f)(1).

Other input errors

The AER identified and corrected the following input errors in the proposed RFM:

- The AER amended the 2006–07 actual inflation input in the proposed RFM from the proposed 4.24 per cent to 2.44 per cent. The amended value is consistent with the approved MAR CPI adjustment for that year.[552]
- The AER changed the 2007–08 nominal WACC input from 8.86 per cent to 8.30 per cent to be consistent with the approved WACC for the 1 January 2003 to 30 June 2008 regulatory control period.[553]
- The AER found the actual capex and disposal amounts in the proposed RFM reconcile with the regulatory accounting data except for 2007–08 actual capex. It thus amended the actual capex inputs for 2007–08 from $165.4 million to $167.8 million to reflect the audited regulatory account data for that year.[554]

The net effect of these amendments is to reduce the proposed opening RAB at 1 July 2013 by $1.7 million.

Energy Consumers Coalition of South Australia's (ECCSA) submission noted that ElectraNet's proposed depreciation schedule did not include an asset life for the land and easements asset classes.[555] The AER notes that ElectraNet's land and easements assets were treated as non-depreciating assets and the AER did not apply an economic life to these asset classes for the 2008–13 regulatory control period.[556] Therefore, the AER accepts ElectraNet's standard and remaining asset lives inputs in the proposed RFM for actual depreciation purposes. This is because the proposed inputs are consistent with the approach allowed in the 2008–13 transmission determination.[557] The AER's consideration of whether land and easements assets should be subject to depreciation over the 2013–18 regulatory control period is discussed in attachment 8.

7.4.2 Forecast closing RAB as at 30 June 2018

The AER forecasts ElectraNet's closing RAB will be $2560.0 million by 30 June 2018, which represents a 10.5 per cent reduction on ElectraNet's proposal. This reduction reflects the AER's draft decision on the inputs for determining the forecast RAB in the PTRM. The South Australian Council of Social Service (SACOSS) submitted that the growth of the RAB is important because of its close correlation to the revenue requirements.[558] The AER's draft decision on the forecast RAB reflects those aspects of the draft decision that relate the value of RAB. To determine the forecast RAB value for ElectraNet, the AER amended the following PTRM inputs:

- It reduced ElectraNet's proposed opening RAB as at 1 July 2013 by $22.1 million or 1.1 per cent (section 7.4.1).
- It reduced ElectraNet's proposed forecast capex by $252.3 million or 28.2 per cent (attachment 4).

552 Based on March quarter 2007 and March quarter 2006 all groups CPI for the weighted average of eight capital cities. ABS, Consumer price index, Australia, June 2012, cat. no. 6401.0, tables 3 and 4.
553 ACCC, *Decision: South Australian transmission network revenue cap 2003 to 2007–08*, December 2002, p. 41.
554 ElectraNet, *Email response to information request AER RP 012, roll forward model*, ENET 223, 6 August 2012, pp. 2–3.
555 ECCSA, *AER review of SA electricity transmission 2012*, August 2012, pp. 22–23.
556 AER, *Draft decision: ElectraNet transmission determination 2008–13*, November 2007, p. 212.
557 NER, S6A.2.1(f)(5).
558 SACOSS, *Submission to the AER on ElectraNet's 2013–18 revenue proposal,* August 2012, p. 2.

- It reduced ElectraNet's proposed forecast regulatory depreciation allowance by $5.5 million or 2.4 per cent (attachment 8).

7.5 Revisions

Revision 7.1: the AER determined that ElectraNet's opening RAB at 1 July 2013 is $2077.8 million as set out in table 7.1.

Revision 7.2: the AER has determined ElectraNet's forecast opening RAB for each year of the 2013–18 regulatory control, as set out in table 7.2

8 Regulatory depreciation

The AER is required to make a decision on ElectraNet's indexation of the regulatory asset base (RAB) and depreciation building blocks over the 2013–18 regulatory control period.[559] The regulatory depreciation allowance (or return of capital) is the net total of the straight line depreciation (negative) and the indexation of the RAB (positive), which comprises about 14 per cent of ElectraNet's proposed total revenue.[560]

This attachment sets out the AER's draft decision on ElectraNet's regulatory depreciation allowance. It also presents the AER's draft decision on the proposed depreciation schedule, including an assessment of the standard and remaining asset lives used for depreciation purposes over the 2013–18 regulatory control period.

8.1 Draft decision

The AER does not accept ElectraNet's proposed regulatory depreciation allowance of $233.6 million ($ nominal) for the 2013–18 regulatory control period, and determined a regulatory depreciation allowance of $228.1 million ($ nominal). The AER's draft decision represents a decrease of $5.5 million (or 2.4 per cent) to the proposal, made for the following reasons:

- The AER does not accept ElectraNet's proposed depreciation schedule for the 'Transmission line refit' asset class. This is because the proposed standard asset life of 15 years assigned does not reflect the economic life of the assets in this asset class.[561] The AER determines a standard asset life of 27 years, which reflects the weighted average of the economic lives of the assets used for the forecast transmission line refurbishment works.

- The AER accepts ElectraNet's proposal to accelerate the depreciation of the residual values of the replaced assets, such as substation and transmission line assets, for the 2013–18 regulatory control period. However, the AER has reduced the amounts allocated for accelerated depreciation purposes to $3.6 million from the proposed $5.6 million to reflect the reductions to ElectraNet's proposed forecast replacement capex discussed in attachment 4.

- The AER accepts ElectraNet's proposed weighted average method to calculate the remaining asset lives as at 1 July 2013. In accepting the weighted average method, the AER has updated ElectraNet's remaining asset lives as at 1 July 2013 to reflect the AER's adjustments to the RAB roll forward in the RFM, as discussed in attachment 7.[562]

- The AER's determinations on other components of ElectraNet's proposal also affect the regulatory depreciation allowance.[563] Discussed in other attachments, these determinations include the forecast capex (attachment 4) and the opening RAB as at 1 July 2013 (attachment 7).

Table 8.1 sets out the AER's draft decision on ElectraNet's annual regulatory depreciation allowance for the 2013–18 regulatory control period.

559 NER, clauses 6A.5.4(a)(1) and (3).
560 ElectraNet, *Revenue proposal*, p. 151.
561 NER, clause 6A.6.3(b)(1).
562 At the time of this draft decision, the roll forward of ElectraNet's RAB includes estimated capex values for 2011–12 and 2012–13. The AER will update the 2011–12 estimated capex value for its final decision with the actual value. The AER may update the 2012–13 capex value if ElectraNet's revised proposal includes a more up-to-date estimate. The 2011–12 and 2012–13 capex values are used to calculate the weighted average remaining tax asset lives in the RFM. Therefore, the AER will recalculate ElectraNet's remaining tax asset lives as at 1 July 2013 using the method approved in this draft decision to reflect the actual 2011–12 capex (and the 2012–13 capex estimate where relevant) for the final decision.
563 NER, clause 6A.6.3(a)(1).

Table 8.1 AER's draft decision on ElectraNet's depreciation allowance for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Straight-line depreciation	84.6	93.5	108.0	113.1	119.4	518.6
Less: inflation indexation on opening RAB	51.9	56.0	58.3	61.0	63.2	290.5
Regulatory depreciation	32.6	37.5	49.7	52.0	56.2	228.1

Source: AER analysis.

8.2 ElectraNet's proposal

ElectraNet proposed a forecast regulatory depreciation allowance of $237.8 million ($ nominal) over the 2013–18 regulatory control period as shown in Table 8.2. ElectraNet modelled and forecast its depreciation allowance at an asset class level using straight line depreciation, assigning a weighted average standard asset life and remaining asset life to all assets in a class. If assets are to be decommissioned during the regulatory control period, those assets with a residual value are written-off over the same period on a straight-line depreciation basis (accelerated depreciation). ElectraNet used the AER's post tax revenue model (PTRM) to calculate its regulatory depreciation allowance.[564]

ElectraNet stated it has not changed the standard asset lives of the existing asset classes from the 2008–13 regulatory control period. However, ElectraNet proposed to introduce an asset class for transmission line refit expenditure, adopting a standard asset life of 15 years for this asset class. ElectraNet stated that following refit works the remaining life of the refitted transmission lines will be extended beyond the remaining term (if any) of the standard asset life of 55 years. The proposed 15 year standard asset life for the asset class in respect of the refit works expenditure reflects the average life extension for the assets subject to such works, assessed on a case by case basis. It further stated the remaining life of the underlying transmission asset (when applicable) is then adjusted to align with the extended asset life, and depreciated over the same timeframe on a straight line basis.[565]

564 ElectraNet, *Revenue proposal*, p. 120.
565 ElectraNet, *Revenue proposal*, p. 121.

Table 8.2 ElectraNet's proposed depreciation allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Straight line depreciation	87.6	97.5	112.7	118.4	129.1	545.2
Less: inflation indexation on opening RAB	52.5	57.4	61.5	66.1	70.0	307.5
Regulatory depreciation	35.1	40.1	51.2	52.3	59.1	237.8

Source: ElectraNet, *Revenue proposal*, p. 123.

8.3 Assessment approach

The AER is required to determine the regulatory depreciation allowance as a part of a TNSP's annual building block revenue requirement.[566] The AER's calculation of ElectraNet's regulatory depreciation building block is made in the PTRM and depends on several components. The calculation of depreciation in each year is governed by the value of assets included in the RAB at the beginning of the regulatory year and the depreciation schedules.

The AER's standard approach to calculating depreciation is to employ the straight-line method as set out in the PTRM. The AER considers that the straight-line method of depreciation satisfies the National Electricity Rules (NER) requirements in clause 6A.6.3(b). It provides an expenditure profile that reflects the nature of the assets over their economic life.[567] Regulatory practice has been to assign a standard asset life to each category of assets that represents the economic or technical life of the asset or asset class. The AER must consider whether the proposed depreciation schedules conform to the following requirements:

- The schedules depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.[568]
- The sum of the real value of the depreciation attributable to any asset or category of assets must be equivalent to the value at which that asset or category of assets was first included in the RAB for the relevant transmission system.[569]

To the extent that a TNSP's revenue proposal does not comply with the above requirements, the AER must determine the depreciation schedules for calculating the depreciation for each regulatory year.[570]

The regulatory depreciation allowance is an output of the PTRM. The AER therefore has assessed ElectraNet's proposed regulatory depreciation allowance by analysing the proposed inputs to the PTRM for calculating the regulatory depreciation allowance. These inputs include:

- the forecast net capex in the 2013–18 regulatory control period
- the forecast inflation rate for the 2013–18 regulatory control period
- the opening RAB as at 1 July 2013

566 NER, clause 6A.5.4(a)(3).
567 NER, clause 6A.6.3(b)(1).
568 NER, clause 6A.6.3(b)(1).
569 NER, clause 6A.6.3(b)(2).
570 NER, clause 6A.6.3(a)(2)(ii).

- the standard asset life for each asset class—used for calculating the depreciation of new assets associated with forecast net capex in the 2013–18 regulatory control period
- the remaining asset life for each asset class—used for calculating the depreciation of existing assets associated with the opening RAB as at 1 July 2013.

The AER's determinations affecting the first three inputs in the above list are discussed elsewhere: forecast net capex (attachment 4) and forecast inflation (attachment 6), opening RAB (attachment 7). The AER's draft decision on ElectraNet's regulatory depreciation allowance reflects the AER's determinations on these building block components. The AER's assessment approach on the remaining two inputs in the above list is set out below.

The AER assesses ElectraNet's proposed standard asset lives, where necessary, against:

- the approved standard asset lives in the transmission determination for the 2008–13 regulatory control period
- the standard asset lives of comparable asset classes approved in the AER's recent transmission determinations for other TNSPs.

The AER's standard approach determines the remaining asset lives using the weighted average method as set out in the AER's roll forward model (RFM). The weighted average method rolls forward the remaining asset life for an asset class from the beginning of the current regulatory control period. This approach reflects the mix of assets within that asset class, when they were acquired over that period (or if they were existing assets at the beginning), and the remaining value of those assets (used as a weight) at the end of the period. The AER will assess the outcomes of other approaches against the outcomes of this standard approach.

8.4 Reasons for draft decision

The AER accepts ElectraNet's proposal to use the straight-line method for calculating the regulatory depreciation allowance as set out in the PTRM. However, the AER has decreased ElectraNet's proposed regulatory depreciation allowance by $5.5 million ($ nominal) or 2.4 per cent, for the following reasons:

- The AER does not accept ElectraNet's proposed standard asset life of 15 years for the 'Transmission line refit' asset class, and has determined a standard asset life of 27 years for this asset class.
- The AER has updated ElectraNet's remaining asset lives as at 1 July 2013 to reflect the AER's adjustments to the actual capex in the RAB roll forward in the RFM.
- The AER has reduced ElectraNet's proposed amounts allocated for accelerated depreciation purposes to $3.6 million from the proposed $5.6 million.
- The AER's determinations on other components of ElectraNet's revenue proposal including the forecast capex (attachment 4) and the opening RAB at 1 July 2013 (attachment 7) also impact the forecast regulatory depreciation allowance.

This section sets out the AER's consideration of the proposed standard asset lives and the remaining asset lives, and accelerated depreciation. It also sets out the AER's consideration of the Electricity Consumers Coalition of South Australia's (ECCSA) submission on the depreciation and indexation of ElectraNet's land and easement assets.

8.4.1 Standard asset lives

The AER accepts the majority of ElectraNet's proposed standard asset lives, because they are:

- consistent with the AER's approved standard asset lives for ElectraNet's 2008–13 regulatory control period
- comparable with the standard asset lives approved in the AER's recent transmission determinations.

However, the AER does not accept the proposed standard asset life of 15 years for the 'Transmission line refit' asset class for the forecast transmission line refurbishment capex. It considers the proposed 15 years does not represent the standard economic lives of the assets in this asset class. Table 8.3 sets out the AER's draft decision on ElectraNet's standard asset lives for the 2013–18 regulatory control period.

Table 8.3 AER's draft decision on ElectraNet's standard asset lives and remaining asset lives as at 1 July 2013 (years)

Asset class	Standard asset life	Remaining asset life as at 1 July 2013
Commercial buildings	30.0	23.9
Communications—civil	55.0	45.0
Communications—other	15.0	12.0
Computers, software, and office machines	4.0	3.5
Easement	n/a	n/a
Land	n/a	n/a
Network switching centres	5.0	4.3
Office furniture, movable plant, and miscellaneous	10.0	9.1
Refurbishment[b]	10.0	4.4
Substation primary plant	44.8	33.3
Substation demountable buildings	15.0	14.4
Substation establishment	55.0	53.3
Substation fences	35.0	35.0
Substation secondary systems—electromechanical	27.0	17.2
Substation secondary systems—electronic	15.0	14.3
Transmission lines—overhead	55.0	31.1
Transmission lines—underground	40.0	36.6
Working capital	n/a	n/a
Accelerated depreciation	5.0	5.0
Refurbishment projects 2008–13	12.5	12.5
Equity raising cost—2003 opening RAB and 2003–08 capex	43.0	38.0
Equity raising cost 2013–18	43.0	n/a
Transmission lines refit—insulators replacement 2013–18[a]	27.0	n/a

n/a: not applicable.
a: The AER has changed the name of the asset class from 'Transmission line refit' to 'Transmission lines refit—insulators replacement 2013–18' in the PTRM .
b: Refurbishment projects for the 2003–08 regulatory control period.
Source: AER analysis

'Transmission line refit' asset class

ElectraNet proposed a standard asset life of 15 years for the 'Transmission line refit' asset class for its forecast transmission line refurbishment capex. The AER requested ElectraNet to provide further information on the asset types used for the transmission line refit works and method used for determining the proposed standard asset life of 15 year. ElectraNet stated that the proposed line refurbishment projects involve the replacement of the insulators on six of ElectraNet's transmission lines, as shown in Table 8.4. ElectraNet's transmission line asset class comprises four components: conductors, insulators, supporting systems and subcomponents. The proposed standard asset life of 15 years is based on the average remaining life of the next limiting components for these lines identified by conditional assessment.[571]

Table 8.4 ElectraNet's transmission line refit asset lives analysis

Line refit project	Remaining life before refit (years)	Insulator type expected life (years)	Next limiting component by conditional assessment	Remaining life of the next limiting component (years)	Length of line (km)
Line 1	–1	20	Support systems (footings)	10–15	282.8
Line 2	9	40	All	15–20	36.9
Line 3	8	40	Support systems (towers, footings)	15–20	121.4
Line 4	–9	40	Support systems (Towers)	15–20	46.2
Line 5	7	40	All	15–20	27.4
Line 6	20	40	Support systems (Poles)	15–20	24.5

Source: ElectraNet, *Email response to information request AER RP 15, Transmission line refit, ENET230*, 15 August 2012, p. 5.

The AER does not consider the proposed 15 years reflect the nature of the assets over the economic life of the assets within this asset class.[572] This is because ElectraNet's approach for determining the standard asset life underestimated the economic life of the insulators being replaced as part of the transmission line refit capex. The insulators used for the line refurbishment works have a technical life of 20 and 40 years.[573] The AER's view is that the insulators could reasonably be expected to be in service until the end of their technical lives. Therefore, the expected economic life of the insulators should be much longer than the proposed 15 years. The reasons for this view are:

- ElectraNet is able to refurbish or replace the remaining transmission line components as they expire resulting in further extensions to the life of the underlying transmission lines. This approach enables ElectraNet to continue to use the insulators until they reach the end of the intended technical life. ECCSA submitted that the refitted transmission lines might well have a longer life than the proposed 15 years.[574]

- ElectraNet's asset management strategy suggests that it conducts systematic conditional assessments of its transmission lines at the component level. Its transmission line refurbishment decisions are made at the component/asset type level supporting the position of component based replacement/refurbishment to extend the life of the line, as opposed to replacing the entire

571 ElectraNet, *Email response to information request AER RP 15, Transmission line refit,* ENET230, 15 August 2012, p. 5.
572 NER, clause 6A.6.3(b)(1).
573 ElectraNet, *Email response to information request AER RP 15, Transmission line refit*, ENET230, 15 August 2012, p. 3.
574 ECCSA, *AER review of SA electricity transmission 2012*, August 2012, p. 24.

line as a single unit.[575] The AER notes that ElectraNet has no current plans to replace any or all of the refitted transmission lines after 15 years.[576]

- There is no evidence that ElectraNet, in the past, has systematically disposed of assets, such as insulators, before they reach the end of their technical life. The AER considers that it is not efficient or prudent for a TNSP to systematically dispose of an asset or components of an asset before they reach the end of the technical life without any justification.
- The practice of ongoing renewal and refurbishing components of line assets to keep the existing lines in service has been used by other TNSPs.[577]

For these reasons, the AER considers ElectraNet's approach to determining the standard asset life for the 'transmission line refit' asset class is not appropriate. The AER expects the insulators component of the transmission lines should, in general, continue to be in service for their full economic life. In any event, if they could not be used until the end of their economic life, then upon justification ElectraNet may propose accelerated depreciation of the residual value at a future date.

The AER considers that a key aspect in determining an appropriate standard asset life for the 'Transmission line refit' asset class is the expected economic lives of the various assets used for the line refurbishment works. The assets used for the refurbishment works have an economic life that is much longer than the proposed 15 years. Therefore, the AER calculated a weighted average of the standard asset life of 27 years by weighting together the economic lives of the insulators using the proportion of capex for each insulator type as weights. It considers this standard asset life creates a depreciation profile that reflects the nature of the category of assets in the 'Transmission line refit' asset class.[578]

Further, the AER has renamed ElectraNet's proposed asset class 'Transmission line refit', 'Transmission lines refit—insulators replacement 2013–18'. This is because the proposed standard asset life of 15 years is based on the forecast refurbishment work on only six transmission lines and a single component of the transmission line. Therefore, the 'Transmission line refit' asset class should not be used for all future transmission line refurbishment capex. ECCSA also submitted that only the cost of the new assets used to extend the life of the transmission lines is subject to the new depreciation rate.[579] The AER has therefore renamed this class to better represent the nature of the forecast transmission line refurbishment capex for the 2013–18 regulatory control period.

8.4.2 Remaining asset lives at 1 July 2013

The AER accepts ElectraNet's proposed weighted average method to calculate the remaining asset lives as at 1 July 2013.[580] In accepting the weighted average method, the AER has updated ElectraNet's remaining asset lives as at 1 July 2013 to reflect the AER's adjustments to the actual capex in the RAB roll forward in the RFM, as discussed in attachment 7.[581] This is because the actual

[575] ElectraNet, *Asset management strategy*, May 2012, pp. 17–18.
[576] Email response to information request AER RP 33, Transmission line refit asset class, ENET262, 4 October 2012, p. 5.
[577] AER, *Final decision: TransGrid transmission determination 2009–10 to 2013–14, April 2009*, pp. 109–110. PB, *TransGrid revised revenue proposal- standard asset lives for replacement asset classes- Prepared for the AER*, 21 April, p. 11.
[578] NER, clause 6A.6.3(b)(1).
[579] ECCSA, *AER review of SA electricity transmission 2012*, August 2012, p. 24.
[580] The AER adjusted the remaining asset life roll forward formula in the RFM to exclude the input value for assets under construction. This is because the remaining asset lfe roll forward calculation of the opening RAB capital stream should only reflect as-commissioned assets.
[581] At the time of this draft decision, the roll forward of ElectraNet's RAB includes estimated capex values for 2011–12 and 2012–13. The AER will update the 2011–12 estimated capex value for its final decision with the actual value. The AER may update the 2012–13 capex value if ElectraNet's revised proposal includes a more up-to-date estimate. The 2011–12 and 2012–13 capex values are used to calculate the weighted average remaining tax asset lives in the RFM. Therefore, the AER will recalculate ElectraNet's remaining tax asset lives as at 1 July 2013 using the method approved in this draft decision to reflect the actual 2011–12 capex (and the 2012–13 capex estimate where relevant) for the final decision.

capex values are inputs for calculating the weighted average remaining asset lives in the RFM. Table 8.3 sets out the AER's draft decision on ElectraNet's remaining asset lives as at 1 July 2013 for the 2013–18 regulatory control period.

8.4.3 Accelerated depreciation

ElectraNet proposed to depreciate the residual values of the assets to be replaced during the 2013–18 regulatory control period within that period. In its 2008 transmission determination for ElectraNet, the AER allowed accelerated depreciation for the residual values of the replaced assets over the 2008–13 regulatory control period.[582] Consistent with that determination, the AER accepts ElectraNet's proposal to accelerate the depreciation of the residual values of the replaced assets for the 2013–18 regulatory control period. However, the AER has reduced the amounts allocated for accelerated depreciation purposes from $5.6 million to $3.6 million, due to the AER's adjustment to ElectraNet's proposed replacement capex discussed in attachment 4.[583]

8.4.4 Depreciation and indexation of land and easement assets

ECCSA submitted that land and easements should not be automatically inflated by the consumer price index (CPI) and receive a rate of return forever. It suggested land 'should be depreciated to allow for the cost of remediation to return the land to the state it was in at the time of acquisition'. It also suggested easement costs are opex, and therefore should not be capitalised.[584]

ElectraNet did not propose standard asset lives for its 'Land' and 'Easements' asset classes for depreciation purposes. The AER accepts this approach, because it considers expenditures associated with land and easement assets should be not depreciated, for the following reasons:

- In previous decisions, the AER has consistently treated land and easements assets as non-depreciating assets and has not applied an economic life to such asset categories.
- According to the Australian accounting standards, land is generally not depreciable because land values tend to increase over time, given limited supply of, and increasing demand for, land.[585] The Australian Taxation Office (ATO) also excludes land from the definition of a depreciating asset.[586]
- Easements are rights acquired over land for use of that land in a specific way, and they are usually granted in perpetuity. For this reason, easements are generally not subject to replacement, and depreciation does not apply. Further, the ATO determined that easements must be treated as capital assets.[587] The costs associated with acquiring easements are also generally capitalised because of the long useful life of easements. The AER's approach is therefore consistent with the ATO's treatment for easements.

For these reasons, the AER considers ElectraNet should not receive a depreciation allowance for land and easements assets, because those assets are considered to be non-depreciating. Therefore, ElectraNet's proposal to not depreciate its land and easements assets over the 2013–18 regulatory control period is appropriate.

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582 AER, *Post merits review final decision: PTRM for ElectraNet for the 2008–13 regulatory control period*, 'Input' sheet.
583 ElectraNet, *Response to AER information request AER RP 16: CAPEX impact of AEMO's 2012 demand forecast ENET238*, August 2012.
584 ECCSA, *AER review of SA electricity transmission 2012*, August 2012, pp. 22–23.
585 Australian accounting standard board, *Accounting standard AASB1021: Depreciation, August 1997*, pp. 10–11.
586 ATO, *Guide to depreciating assets 2011*, 2011, p. 3.
587 ATO, *Tax ruling NO. IT 2561—Income tax: capital gains: Grants of easements, profits a prendre and licences*, 21 September 1989, paragraph 16.

Further, the land and easement assets will form part of ElectraNet's RAB if these assets are used to provide prescribed transmission service.[588] As part of the adjustment to the RAB under the NER, ElectraNet must adjust its RAB for inflation. It will also receive a rate of return on its RAB over the 2013–18 regulatory control period as required by the NER.[589] The AER's consideration of ElectraNet's proposed land and easement capex for the 2013–18 regulatory control period are discussed in attachment 4.

8.5 Revisions

Revision 8.1: the AER determined ElectraNet's forecast regulatory depreciation allowance to be $228.1 million ($ nominal) over the 2013–18 regulatory control period as set out in table 8.1.

Revision 8.2: the AER determined ElectraNet's standard asset lives and remaining asset lives as at 1 July 2013 for the 2013–18 regulatory control period as set out in Table 8.3.

[588] NER, clause 6A.6.1(a).
[589] NER, clause 6A.6.2.

9 Corporate income tax

The AER is required to make a decision on the estimated cost of corporate income tax.[590] Under the post tax framework, a corporate income tax allowance is calculated as part of the building block assessment using the AER's post tax revenue model (PTRM).

This attachment sets out the AER's draft decision on ElectraNet's proposed corporate income tax allowance for the 2013–18 regulatory control period. It also presents the AER's assessment on the proposed tax asset base (TAB), and the standard and remaining tax asset lives used to estimate tax depreciation for the purpose of calculating the estimated cost of corporate income tax allowance.

9.1 Draft decision

The AER does not accept ElectraNet's proposed estimated cost of corporate income tax allowance of $30.7 million ($ nominal) for the 2013–18 regulatory control period. The AER determines the estimated corporate income tax allowance of ElectraNet to be $26.8 million ($ nominal), which represents a reduction of $3.9 million (or 12.7 per cent) to the proposal. This reduction has been made for the following reasons:

- the AER accepts ElectraNet's proposed method of establishing the opening TAB as at 1 July 2013. However, the AER increased ElectraNet's proposed TAB as at 1 July 2013 to $1407.0 million ($ nominal) from $1405.0 million. This is because the AER adjusted the actual capex values and removed two incorrect adjustments to the opening TAB values in the RFM.

- the AER accepts ElectraNet's proposed standard tax asset lives for the majority of its asset classes, except for the ‘Equity raising cost 2013–18’ and ‘Transmission line refit’ asset classes. The AER changed the proposed standard tax asset life for the ‘Equity raising cost 2013–18’ asset class to 5 years from 43 years. It changed the proposed standard tax asset life for the ‘Transmission line refit’ asset class to 27 years from 47.5 years.

- the AER accepts ElectraNet's proposed weighted average method to calculate the remaining tax asset lives at 1 July 2013. In accepting the weighted average method, the AER has updated the proposed remaining tax lives to reflect the AER's adjustments to ElectraNet's actual capex in the RFM.

- the AER's determinations on other building blocks including forecast opex (attachment 5) and cost of capital (attachment 6) also impact the estimated corporate income tax allowance.[591]

Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 24.0 per cent for this draft decision. Table 9.1 sets out the AER's draft decision on ElectraNet's estimated corporate income tax allowance over the 2013–18 regulatory control period.

[590] NER, clause 6A.5.4(a)(4).
[591] NER, clause 6A.6.4.

Table 9.1 AER's draft decision on ElectraNet's corporate income tax allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Tax payable	13.8	14.6	15.6	17.8	14.9	76.7
Less: value of imputation credits	9.0	9.5	10.1	11.6	9.7	49.9
Net corporate income tax allowance	4.8	5.1	5.4	6.2	5.2	26.8

Source: AER analysis.

9.2 ElectraNet's proposal

ElectraNet proposed a corporate income tax allowance of $30.7 million ($ nominal) over the 2013–18 regulatory control period as shown in Table 9.2.[592] It estimated the corporate income tax allowance using the AER's PTRM and the following input values:[593]

- an opening TAB of $1405.0 million ($ nominal) as at 1 July 2013
- an expected statutory income tax rate of 30 per cent per year
- a value for the assumed utilisation of imputation credits (gamma) of 0.65
- standard tax asset lives and remaining tax asset lives contained in its proposed PTRM.[594]

Table 9.2 ElectraNet's proposed corporate income tax allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Tax payable	15.6	16.5	17.8	20.0	17.9	87.7
Less: value of imputation credits	10.1	10.7	11.6	13.0	11.6	57.0
Net corporate income tax allowance	5.5	5.8	6.2	7.0	6.3	30.7

Source: ElectraNet, *Regulatory proposal*, p. 130.

9.3 Assessment approach

The AER is required to estimate ElectraNet's cost of corporate income tax for each year of the 2013–18 regulatory control period under clause 6A.6.4(a) of the National Electricity Rules. The AER's approach for calculating ElectraNet's cost of corporate income tax is set out in the AER's PTRM and involves the following steps:

- First, the AER estimates the annual taxable income that would be earned by a benchmark efficient TNSP operating ElectraNet's business.[595] A TNSP's taxable income is calculated by adjusting the AER's approved forecast revenues by estimates of tax expenses. Using the PTRM, the AER models ElectraNet's tax expenses, including interest tax expense and tax depreciation, over the 2013–18 regulatory control period. The interest tax expense is estimated using the benchmark 60 per cent gearing, rather than ElectraNet's actual gearing. Tax depreciation is calculated using a separate asset base value, and standard and remaining asset lives for tax

592 ElectraNet, *Revenue proposal*, 31 May 2012, p. 130.
593 ElectraNet, *PTRM*, ENET077, May 2012.
594 ElectraNet, *PTRM*, ENET077, May 2012.
595 NER, clause 6A.6.4(a)(2).

purposes. All tax expenses (including other expenses such as opex) are offset against the TNSP's forecast revenue to estimate the taxable income.

- The statutory income tax rate is then applied to the estimated annual taxable income to arrive at a notional amount of tax payable.
- The AER then applies a discount to that notional amount of tax payable to account for the assumed utilisation of imputation credits (gamma).
- The final estimate of tax payable net of assumed utilised imputation credits is then included as a separate building block in determining the TNSP's annual building block revenue requirement.

The corporate income tax allowance is an output of the AER's PTRM. The AER therefore has assessed ElectraNet's proposed corporate income tax allowance by analysing the proposed inputs to the PTRM for calculating the tax allowance. These inputs include:

- The opening TAB as at 1 July 2013: The AER considers that the roll forward of the opening tax asset base to 1 July 2013 should be based on the approved opening TAB as at 1 July 2008 and ElectraNet's actual capex in the 2008–13 regulatory control period.
- The standard tax asset life for each asset class: The AER assesses ElectraNet's proposed standard tax asset lives, where necessary, against those prescribed by the Commissioner for taxation in Tax Ruling 2012/2 and the approved standard tax asset lives in the 2008–13 regulatory control period.
- The remaining tax asset life for each asset class at 1 July 2013: The AER's preferred method to determine the remaining tax asset lives is the weighted average method.[596] The AER considers the weighted average method provides a better reflection of the mix of assets within an asset class and the effective life of the asset class.
- The income tax rate: The statutory income tax rate is 30 per cent per year.
- The value of gamma: The value of gamma for ElectraNet is 0.65, which is consistent with the value determined in the WACC review.[597]

9.4 Reasons for draft decision

The AER does not accept ElectraNet's proposed estimated cost of corporate income tax allowance of $30.7 million ($ nominal) for the 2013–18 regulatory control period. This is because the AER adjusted several of ElectraNet's proposed inputs to the PTRM for tax purposes, which include:

- the opening TAB as at 1 July 2013
- the standard tax asset lives for the 'Equity raising cost 2013–18' and 'Transmission line refit' asset classes
- the remaining tax asset lives at 1 July 2013 for several asset classes.

The AER determines the estimated cost of corporate income tax of ElectraNet to be $26.8 million ($ nominal), which represents a reduction of $3.9 million (or 12.7 per cent) to the proposal.

596 The weighted average method involves weighting the remaining life of each capital stream within an asset class (that is, the opening tax capital value and the capital expenditures for each year) by the closing tax capital value of that capital stream as a proportion of the total closing tax capital value of the asset class as a whole. The resulting individual values for each capital stream are then added together to obtain the overall weighted average remaining life of the asset class.

597 The value of gamma is also discussed in attachment 6 regarding the cost of capital.

9.4.1 Tax asset base as at 1 July 2013

The AER accepts ElectraNet's proposed method to establish the opening TAB as at 1 July 2013. However, the AER does not accept the proposed opening TAB value as at 1 July 2013 of $1405.0 million ($ nominal). The AER determines the value of the opening TAB as at 1 July 2013 to be $1407.0 million ($ nominal), which represents an increase of $2.0 million (or 0.1 per cent) to the proposal. The following are the reasons for this increase:

- ElectraNet advised the AER that it has incorrectly allocated the opening TAB values for the 'Network switching centre' and 'Substation primary plant' asset classes in the proposed RFM.[598] The AER has corrected these input values in the RFM. These amendments increased the proposed opening TAB as at 1 July 2013 by $2.5 million (or 0.2 per cent).
- The AER's adjustments to ElectraNet's actual capex values in the RFM slightly reduced the proposed opening TAB as at 1 July 2013 by about $0.5 million. This is because the actual capex values are inputs for calculating the opening TAB.

Table 9.3 sets out the AER's draft decision on the roll forward of ElectraNet's TAB for the 2008–13 regulatory control period.

Table 9.3 AER's draft decision on ElectraNet's tax asset base roll forward ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13
Opening TAB	874.4	902.2	890.3	948.0	1184.1
Capital expenditure[a]	56.2	19.3	90.6	273.7[b]	271.0[b]
Tax depreciation	–28.4	–31.2	–32.9	–37.7	–48.0
Closing TAB	902.2	890.3	948.0	1184.1	1407.0

Source: AER analysis.
(a) As commissioned, net of disposals.
(b) Based on estimated capex.

9.4.2 Standard tax asset lives

The AER accepts most of ElectraNet's proposed standard tax asset lives because they are:

- broadly consistent with the values prescribed by the Commissioner for taxation in tax ruling 2012/2
- consistent with the AER's approved standard tax asset lives for the 2008–13 regulatory control period.

However, the AER does not accept the proposed standard tax asset life for the 'Equity raising costs 2013–18' and 'Transmission line refit' asset classes, for the following reasons:

- ElectraNet proposed a tax standard life of 43 years for the 'Equity raising cost 2013–18' asset class. The ACCC approved 43 years for amortising equity raising cost at the 2003 reset. However, the Australian Taxation Office (ATO) requires equity raising costs to be depreciated

598 ElectraNet, *Email response to information request AER RP 013, Tax asset base*, ENET 224, 6 August 2012.

over a five-year period on a straight-line basis.[599] In recent transmission determinations, the AER adopted a standard tax asset life of 5 years for the equity raising cost asset class for tax depreciation purposes.[600] Therefore, for this draft decision, the AER will apply a standard tax asset life of 5 years for equity raising costs for ElectraNet over the 2013–18 regulatory control period. This is because the standard tax asset life of 5 years for equity raising cost provides a better estimate of tax depreciation amount for a benchmark efficient TNSP as required by the NER.[601]

- ElectraNet proposed a tax standard life of 47.5 years for the 'Transmission line refit' asset class. The proposed 47.5 years reflects the effective life of a transmission line asset for tax purposes.[602] However the AER considers the standard tax asset life for this asset class should reflect the life of the assets used for the transmission line refit works. The assets used are insulators which have an average economic life of 27 years, as discussed in attachment 8. The AER has therefore changed the proposed standard tax asset life to 27 years, consistent with the standard asset life of this asset class for regulatory depreciation purposes. This is because the AER considers that a standard tax asset life of 27 years for this asset class provides a better estimate of tax depreciation amount for a benchmark efficient TNSP as required by the NER.[603]

Table 9.4 sets out the AER's draft decision on ElectraNet's standard tax asset lives for the 2013–18 regulatory control period.

9.4.3 Remaining tax asset lives

The AER accepts ElectraNet's proposed weighted average method to calculate the remaining tax asset lives as at 1 July 2013. In accepting the weighted average method, the AER has updated the proposed remaining tax asset lives to reflect the AER's adjustments to ElectraNet's actual capex in the RFM, as discussed in attachment 7.[604] This is because the actual capex values are inputs for calculating the weighted average remaining tax asset lives in the RFM.

Table 9.4 sets out the AER's draft decision on ElectraNet's remaining tax asset lives as at 1 July 2013 for the 2013–18 regulatory control period.

599 ATO, *Guide to depreciating assets 2001-02: Business related costs—section 40-880 deductions*, ATO reference; NO NAT7170, p. 25.

600 AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 265–266.

601 NER, clause 6A.6.4(a)(2).

602 ATO, *Taxation ruling*, *TR2012/2*, *Income tax: effective life of depreciating assets (applicable from 1 July 2012)*, July 2012, p. 143.http://law.ato.gov.au/atolaw/view.htm?DocID=TXR%2FTR20122%2FNAT%2FATO%2F00021.

603 NER, clause 6A.6.4(a)(2).

604 At the time of this draft decision, the roll forward of ElectraNet's TAB includes estimated capex values for 2011–12 and 2012–13. The AER will update the 2011–12 estimated capex value for its final decision with the actual value. The AER may update the 2012–13 capex value if ElectraNet's revised proposal includes a more up-to-date estimate. The 2011–12 and 2012–13 capex values are used to calculate the weighted average remaining tax asset lives in the RFM. Therefore, the AER will recalculate ElectraNet's remaining tax asset lives as at 1 July 2013 using the method approved in this draft decision to reflect the actual 2011–12 capex (and the 2012–13 capex estimate where relevant) for the final decision.

Table 9.4 AER's draft decision on ElectraNet's opening tax asset base as at 1 July 2013, standard tax asset lives and remaining tax asset lives as at 1 July 2013

Asset class	Standard tax asset life (years)	Remaining tax asset life at 1 July 2013 (years)
Commercial buildings	40.0	32.1
Communications—civil	12.5	36.8
Communications—other	12.5	10.9
Computers, software, and office machines	3.3	2.8
Easement	n/a	n/a
Land	n/a	n/a
Network switching centres	4.0	4.0
Office furniture, movable plant, and miscellaneous	12.8	11.9
Refurbishment[b]	43.8	31.3
Substation primary plant	40.0	33.1
Substation demountable buildings	40.0	39.4
Substation establishment	40.0	38.4
Substation fences	40.0	40.0
Substation secondary systems—electromechanical	12.5	18.4
Substation secondary systems—electronic	12.5	11.9
Transmission lines—overhead	47.5	27.6
Transmission lines—underground	47.5	44.2
Working capital	n/a	n/a
Accelerated depreciation	5.0	n/a
Refurbishment projects 2008–13	40.0	40.0
Equity raising cost—2003 opening RAB and 2003–08 capex	43.0	38.0
Equity raising cost 2013–18	5.0	n/a
Transmission lines refit—insulators replacement 2013–18[a]	27.0	n/a

n/a: not applicable.
a: The AER has changed the name of the asset class from 'Transmission line refit' to 'Transmission lines refit—insulators replacement 2013–18' in the PTRM, as discussed in attachment 8.
b: Refurbishment projects for the 2003–08 regulatory control period.
Source: AER analysis.

9.5 Revisions

Revision 9.1: the AER determined ElectraNet's estimated cost of corporate income tax allowance to be $26.8 million ($ nominal) over the 2013–18 regulatory control period, as set out in Table 9.1.

Revision 9.2: the AER determined ElectraNet's total opening TAB at 1 July 2013 to be $1407.0 million ($ nominal), as set out in Table 9.3.

Revision 9.3: the AER determined ElectraNet's standard and remaining tax asset lives at the beginning of the 2013–18 regulatory control period to be those as set out in Table 9.4.

10 Maximum allowed revenue

This attachment sets out the AER's draft decision on ElectraNet's maximum allowed revenue (MAR) for the provision of prescribed transmission services during the 2013–18 regulatory control period. Specifically, the attachment addresses:[605]

- the annual building block revenue requirement
- the X factor
- the annual expected MAR
- the estimated total revenue cap, which is the sum of the annual expected MAR.

The AER determines ElectraNet's annual building block revenue requirement using a building block approach. It determines the X factors by smoothing the annual building block revenue requirement over the regulatory control period. The X factor is used in the CPI–X methodology to determine the annual expected MAR (smoothed) for each regulatory year of the 2013–18 regulatory control period.

10.1 Draft decision

The AER's determinations on ElectraNet's proposed building block components have a consequential impact on the annual building block revenue requirement. The AER has recalculated the X factor and the annual expected MAR (smoothed) to reflect the AER's draft decision on ElectraNet's annual building block revenue requirement.

For this draft decision, the AER has approved an estimated total revenue cap of $1507.3 million ($ nominal) for ElectraNet for the 2013–18 regulatory control period.[606] The AER approved X factor is –2.40 per cent per annum from 2014–15 to 2017–18.[607]

Table 10.1 sets out the AER's draft decision on ElectraNet's annual building block revenue requirement, the X factor, the annual expected MAR and the estimated total revenue cap for the 2013–18 regulatory control period.

605 NER, clauses 6A.4.2(a)(1)–(3) and 6A.6.8.
606 The estimated total revenue cap is equal to the total of the annual expected MAR over the 2013–18 regulatory control period.
607 Consistent with ElectraNet's proposal, the AER has determined a constant X factor to apply over the 2013–18 regulatory control period.

Table 10.1 AER's draft decision on ElectraNet's annual building block revenue requirement, annual expected MAR, estimated total revenue cap and X factor ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Return on capital	147.8	159.3	166.0	173.6	179.9	826.6
Regulatory depreciation[a]	32.6	37.5	49.7	52.0	56.2	228.1
Operating expenditure	77.8	83.2	86.5	91.6	95.2	434.3
Efficiency benefit sharing scheme (carryover amounts)	–3.9	–3.9	–1.6	0	5.1	–4.3
Net tax allowance	4.8	5.1	5.4	6.2	5.2	26.8
Annual building block revenue requirement (unsmoothed)	259.2	281.3	306.0	323.5	341.5	1511.5
Annual expected MAR (smoothed)	273.0	286.5	300.8	315.7	331.3	1507.3[b]
X factor (%)	n/a[c]	–2.4	–2.4	–2.4	–2.4	n/a

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
(b) The estimated total revenue cap is equal to the total annual expected MAR.
(c) ElectraNet is not required to apply an X factor for 2013–14 because the MAR is set in this draft decision. The MAR for 2013–14 is around 13.0 per cent lower than the MAR in the final year of the 2008–13 regulatory control period (2012–13) in real terms, or 15.9 per cent lower in nominal terms.

Source: AER analysis.

10.2 ElectraNet's proposal

Based on its proposed building block components, ElectraNet proposed a total (smoothed) revenue cap of $1725.7 million ($ nominal) for the 2013–18 regulatory control period.

Table 10.2 sets out ElectraNet's proposed annual building block revenue requirement, the X factor, the annual expected MAR and the estimated total revenue cap for the 2013–18 regulatory control period.

Table 10.2 ElectraNet's proposed annual building block revenue requirement, annual expected MAR, estimated total revenue cap and X factor ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Return on capital	162.3	177.4	190.1	204.4	216.6	950.8
Regulatory depreciation[a]	35.1	39.3	50.4	51.4	57.4	233.6
Operating expenditure	92.1	101.9	104.9	109.9	113.4	522.2
Efficiency benefit sharing scheme (carryover amounts)	–2.8	–4.8	–4.6	–2.7	1.9	–12.9
Net tax allowance	5.5	5.8	6.2	7.0	6.2	30.7
Annual building block revenue requirement (unsmoothed)	292.2	319.5	347.0	370.0	395.6	1724.4
Annual expected MAR (smoothed)	292.2	316.6	342.9	371.5	402.5	1725.7[b]
X factor (%)	n/a	–5.7	–5.7	–5.7	–5.7	n/a

Source: ElectraNet, *Revenue proposal*, p. 151.
(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
(b) The estimated total revenue cap is equal to the total annual expected MAR.

10.3 Assessment approach

The AER must make a decision on ElectraNet's total revenue cap for the 2013–18 regulatory control period and the MAR for each regulatory year of the 2013–18 regulatory control period.[608] In making its decision, the AER adopts a building block approach.[609] Under this approach the AER determines the value of the building block components that make up the annual building block revenue requirement for each regulatory year. These components include:

- the return on capital, which is a function of the cost of capital and the opening RAB (including the addition of capital expenditure)
- the return of capital (regulatory depreciation), which is based on straight-line depreciation net of the inflation indexation on the opening RAB
- operating expenditure
- the estimated cost of corporate income tax
- other amounts associated with any relevant schemes or carried over from a previous regulatory control period.

The AER developed the post-tax revenue model (PTRM), which brings together the various building block components and calculates the annual building block revenue requirement for each year of the regulatory control period.[610] The PTRM also calculates the X factors required under the CPI–X methodology which is used to escalate the MAR for each year (other than the first year) of the regulatory control period.[611] Using the X factors and annual building block revenue requirement, the annual expected MAR (smoothed) are forecast for each year of the regulatory control period. A

608 NER, clauses 6A.14.1(i)–(ii).
609 NER, clause 6A.5.4.
610 NER, rule 6A.5.
611 NER, clauses 6A.5.3 and 6A.6.8.

TNSP's revenue proposal must be prepared using the AER's PTRM and comply with the requirements of the submission guidelines.[612]

The annual building block revenue requirement can be lumpy over the regulatory control period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. Smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period so that the net present value of the annual expected MAR (smoothed revenues) is equal to the net present value of the annual building block revenue requirement (unsmoothed revenues). That is, a smoothed profile of the expected MAR is determined for the regulatory control period under the CPI–X methodology.

The expected MAR for the first year is generally set equal to the annual building block revenue requirement for the first year of the regulatory control period or a similar amount to the MAR for the last year of the previous regulatory control period:[613]

$$MAR_1 = AR_1 \text{ or } MAR_L$$

where:

MAR_1 = the maximum allowed revenue for year 1 of the next regulatory control period

AR_1 = the annual building block revenue requirement for year 1 of the next regulatory control period

MAR_L = the maximum allowed revenue for the last year of the previous regulatory control period.

The AER uses the PTRM to estimate the expected MAR for each year of the regulatory control period by escalating the previous year's expected MAR using a CPI–X method, based on the MAR that applies to the TNSP in the first year of the regulatory control period. The PTRM incorporates a forecast inflation rate to calculate the expected MAR in nominal dollar terms, whereas the actual MAR is adjusted for actual inflation. This annual adjustment process is set out below.

10.3.1 Annual adjustment process

The MAR for the subsequent year of the regulatory control period requires an annual adjustment based on the previous year's allowed revenue (AR).[614] That is, the subsequent year's AR is determined by adjusting the previous year's AR for actual inflation and the X factor:

$$AR_t = AR_{t-1} \times (1 + \Delta CPI) \times (1 - X_t)$$

where:

AR = the allowed revenue

t = time period/financial year (for t = 2, 3, 4, 5)

612 NER, clause 6A.5.1(a).

613 The MAR for year 1 of the next regulatory control period may include adjustment for the performance incentive that applied during the previous regulatory control period, and under or over recovery adjustments from previous regulatory years.

614 In the case of making the annual adjustment for year 2, the previous year's AR would be the same as the annual building block revenue requirement for year 1.

ΔCPI = the annual percentage change in the ABS Consumer price index all groups, weighted average of eight capital cities from March in year $t-2$ to March in year $t-1$

X = the smoothing factor.

The MAR is determined annually in accordance with the NER by adding to (or deducting from) the AR:

- the service target performance incentive scheme revenue increment (or revenue decrement)[615]
- any approved pass through amounts.[616]

Table 10.3 sets out the timing of the annual calculation of the AR and performance incentive:

$$MAR_t = \text{(allowed revenue)} + \text{(performance incentive)} + \text{(pass through)}$$

$$= AR_t + \left(\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct}\right) + P_t$$

where:

MAR = the maximum allowed revenue

AR = the allowed revenue

S = the revenue increment or decrement determined in accordance with the service target performance incentive scheme

P = the pass through amount that the AER has determined in accordance with clauses 6A.7.2 and 6A.7.3 of the NER

t = time period/financial year (for t = 2, 3, 4, 5)

ct = time period/calendar year (for ct = 2, 3, 4, 5).

Under the NER, a TNSP must also adjust the MAR for under or over recovery amounts.[617]

Table 10.3 Timing of the calculation of allowed revenues and the performance incentive

t	Allowed revenue (financial year)	*ct*	Performance incentive (calendar year)
2	1 July 2014–30 June 2015	2	1 January 2013–31 December 2013
3	1 July 2015–30 June 2016	3	1 January 2014–31 December 2014
4	1 July 2016–30 June 2017	4	1 January 2015–31 December 2015
5	1 July 2017–30 June 2018	5	1 January 2016–31 December 2016

615 NER, clauses 6A.7.4 and 6A.7.3.
616 NER, clauses 6A.7.2 and 6A.7.3.
617 NER, clauses 6A.23.3(c)(2)(iii) and 6A.24.4(c).

10.3.2 Average transmission charges

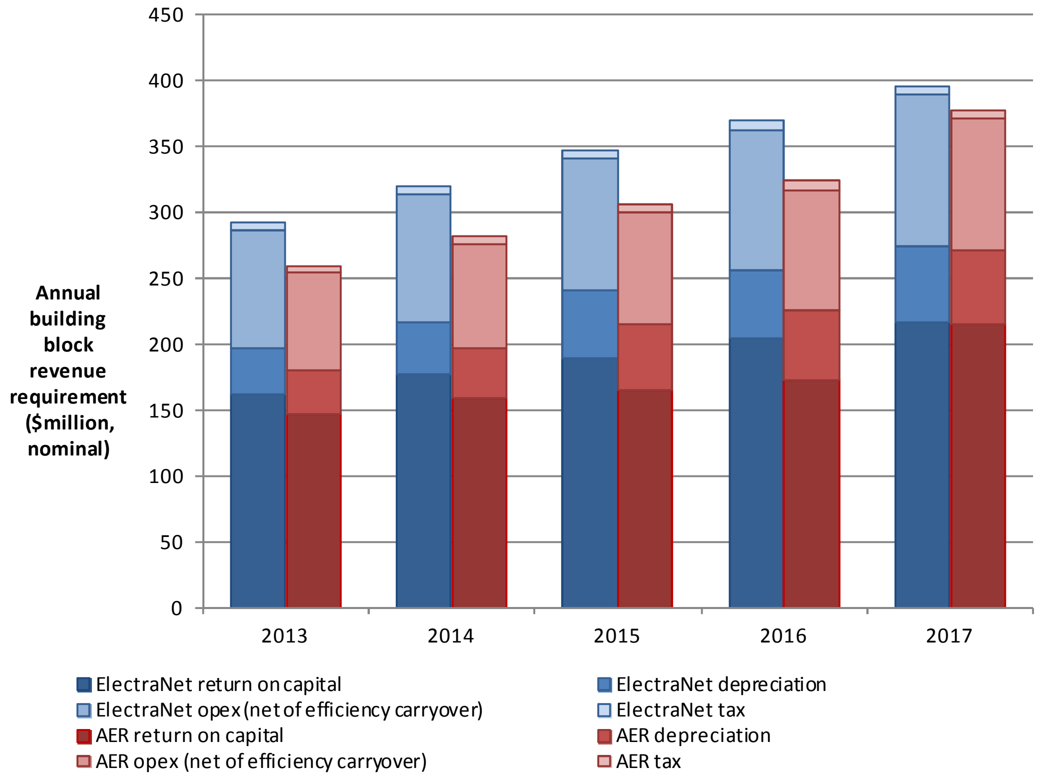
The NER does not require an estimate of transmission price changes for a revenue determination of a TNSP. Nonetheless, the AER typically provides some indicative transmission price impacts flowing from the revenue determination. Although the AER assesses ElectraNet's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. ElectraNet establishes its transmission charges in accordance with its approved pricing methodology and the NER.[618]

10.4 Reasons for draft decision

For this draft decision, the AER has determined a total annual building block revenue requirement of $1511.5 million ($ nominal) for ElectraNet for the 2013–18 regulatory control period. This compares to ElectraNet's proposed total annual building block revenue requirement of $1724.4 million ($ nominal) for this period.[619]

Figure 10.1 shows the AER determined components that make up the annual building block revenue requirement for the 2013–18 regulatory control period and the corresponding building blocks components from ElectraNet's proposal.

Figure 10.1 AER's draft decision and ElectraNet's proposed annual building block revenue requirement ($ million, nominal)



Source: AER analysis.

The AER has calculated the annual building block revenue requirement for ElectraNet based on the revised building block components. The revenues were affected by the AER's changes to ElectraNet's proposed building block components. These changes include:

618 NER, clause 6A.24.1(d).
619 ElectraNet, *Revenue proposal*, p. 151.

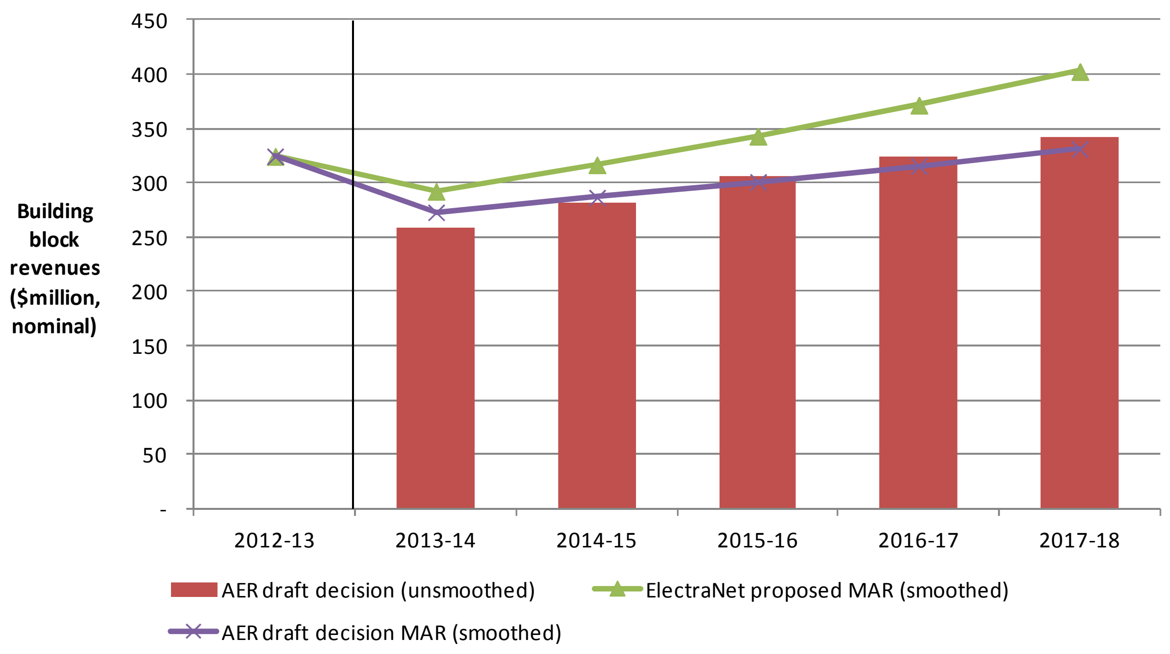
- the opening RAB as at 1 July 2013 (attachment 7) and forecast capital expenditure (attachment 4)
- forecast operating expenditure (attachment 5)
- the rate of return (attachment 6)
- forecast regulatory depreciation (attachment 8)
- the corporate income tax allowance (attachment 9).

10.4.1 X factor, annual expected MAR and estimated total revenue cap

For this draft decision, the AER has determined a revised X factor of –2.40 per cent per annum from 2014–15 to 2017–18. The net present value of the annual building block revenue requirement for the 2013–18 regulatory control period is $1224.1 million ($ nominal) as at 1 July 2013. Based on this net present value and applying the CPI–X method, the AER has determined the annual expected MAR (smoothed) for ElectraNet that increases from $273.0 million in 2013–14 to $331.3 million in 2017–18 ($ nominal).

The resulting estimated total revenue cap for ElectraNet that the AER has approved is $1507.3 million ($ nominal) for the 2013–18 regulatory control period. The total revenue cap is the sum of the annual expected MAR. Figure 10.2 shows the AER's draft decision on ElectraNet's annual expected MAR (smoothed revenue) and the annual building block revenue requirement (unsmoothed revenue) for the 2013–18 regulatory control period.

Figure 10.2 AER's draft decision on ElectraNet's annual expected MAR (smoothed) and annual building block revenue requirement (unsmoothed)



Source: AER analysis.

To determine the expected MAR over the 2013–18 regulatory control period, the AER has set the MAR for the first regulatory year (2013–14) at $273.0 million ($ nominal). This is higher than the annual building block revenue requirement for 2013–14, which is $259.2 million ($ nominal).[620] The AER then applied an X factor of –2.40 per cent per annum to determine the expected MAR in subsequent years. The AER considers that this profile of X factors results in an expected MAR in the last year of the 2013–18 regulatory control period that is as close as reasonably possible to the annual building block revenue requirement for that year as required under the NER.[621] The AER considers a divergence of up to 3 per cent between the expected MAR and annual building block revenue requirement for the last year of the 2013–18 regulatory control period is appropriate, if this can achieve smoother price changes for users over the regulatory control period. In the present circumstances, based on the X factors determined by the AER, this divergence is 3.0 per cent.

The AER has considered stakeholder submissions, which raised concerns with the impact of ElectraNet's revenue determination on the expected electricity price.[622] The AER has smoothed the estimated total revenue cap as much as possible, consistent with the requirements of the NER and NEL.

The average increase in the AER approved expected MAR for ElectraNet is 0.8 per cent per annum ($ nominal) over the 2013–18 regulatory control period. This consists an initial decrease of 15.9 per cent from 2012–13 to 2013–14 and a subsequent average annual increase of 5.0 per cent during the remainder of the 2013–18 regulatory control period. In real terms ($2012–13), the average decrease in the AER approved expected MAR for ElectraNet is 1.7 per cent per annum over the 2013–18 regulatory control period. This consists an initial decrease of 17.9 per cent from 2012–13 to 2013–14 and a subsequent average annual increase of 2.4 per cent during the remainder of the 2013–18 regulatory control period.

The AER's draft decision results in an increase in nominal terms to ElectraNet's total revenue cap relative to that in the 2008–13 regulatory control period. This increase in revenue is primarily because of

- increased opex due to an expanding network and increased field maintenance works
- increased regulatory depreciation allowance due to growth in the RAB.

10.4.2 Indicative average transmission price impact

The AER estimates the effect of the draft decision for the ElectraNet and Murraylink transmission determinations on forecast average transmission charges in South Australia by:

- taking the sum of ElectraNet's annual expected MAR and the proportion of Murraylink's annual expected MAR that is allocated to South Australian customers (45 per cent),[623] and
- dividing it by the forecast annual energy delivered in South Australia.[624]

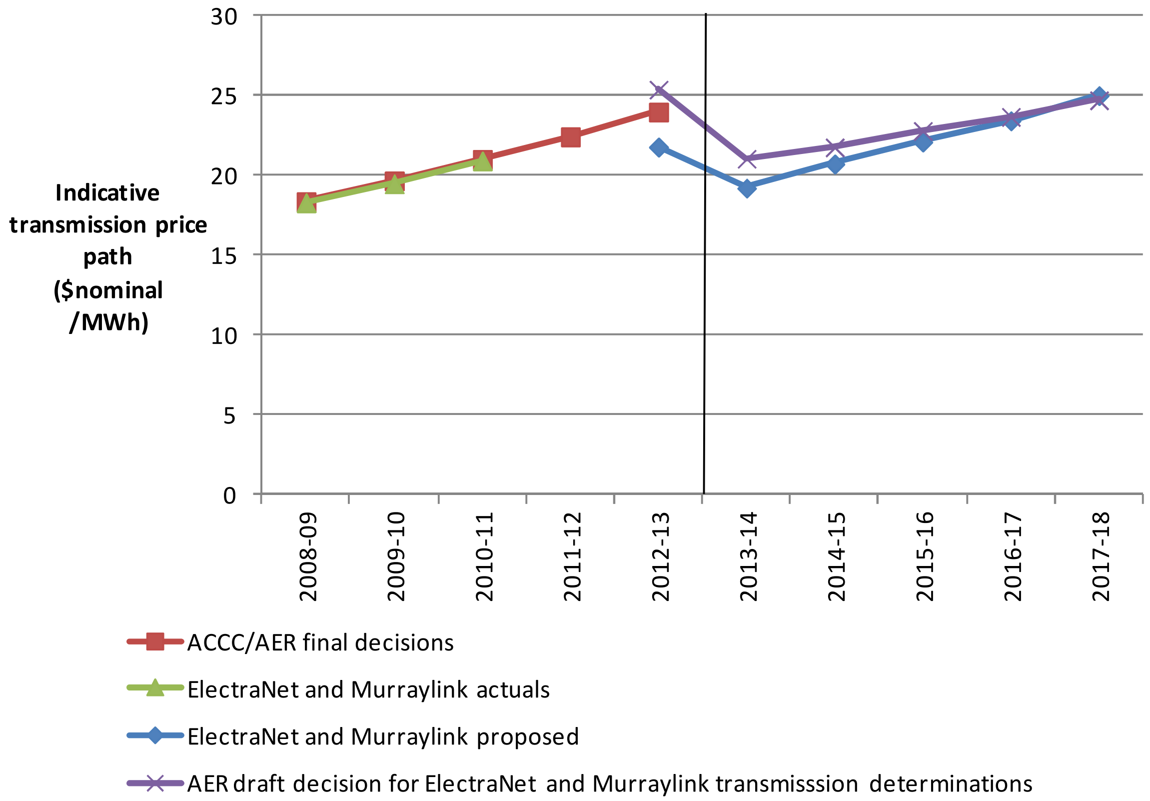
Based on this approach, the AER estimates that its draft decision will result in a small decrease in average transmission charges of 0.1 per cent per annum ($ nominal) from 2012–13 to 2017–18. This estimated decrease in average transmission charges is because the average increase in the AER

620 The MAR for the last year of the 2008–13 regulatory control period (2012–13) is approximately $324.5 million.
621 NER, clause 6A.6.8(c)(2).
622 The South Australian Government, *Letter to the AER*, 27 September 2012; EUAA, *EUAA Submission on ElectraNet's Revenue Proposal for 2013/14-2017/18*, August 2012, p. i.; ECCSA, *Australian Energy Regulator SA Electricity Transmission Revenue Reset—ElectraNet SA Application: A response by The Energy Consumers Coalition of SA*, August 2012, p.3; SACOSS, *SACOSS Submission to the Australian Energy Regulator Consultation on ElectraNet's 2013–18 Transmission Network Revenue Proposal*, August 2012, p. i.
623 Murraylink, *Pricing methodology*, May 2012, p. 3.
624 AEMO, *National electricity forecasting report*, August 2012, table 6-1, Medium (Scenario 3, planning).

approved MAR is slightly lower than the average increase in forecast annual energy delivered in South Australia over the 2013–18 regulatory control period. The average increase in the AER approved MAR for South Australia is 0.8 per cent per annum, whereas the average increase in the forecast energy delivered in South Australia is about 0.9 per cent per annum for the 2013–18 regulatory control period.

Figure 10.3 shows the indicative average transmission charges resulting from its draft decision for the ElectraNet and Murraylink transmission determinations compared with the average transmission charges from 2008 to 2013 in nominal dollar terms. Nominal average transmission charges are forecast to decrease from around $25.40 per MWh in 2012–13 to $24.70 per MWh in 2017–18.

Figure 10.3 Indicative transmission price path from 2008–09 to 2017–18 ($/MWh, nominal)



Source: AER analysis.
Note: The indicative transmission prices for 2012–13 are different, because ElectraNet's proposed energy forecast for 2012–13 is higher than the values used by the AER in the 2008 final decision and in this draft decision.

The Essential Services Commission of South Australia estimates that transmission charges represent approximately 8 per cent on average of a typical customer's electricity bill in South Australia.[625] The AER's draft decision is not expected to contribute towards any price increase for an average South Australian residential electricity customer bill of $1800 ($ nominal, excluding GST) in 2012–13.[626] The AER estimates that its draft decision will result in lower transmission charges on average over the 2013–18 regulatory control period compared to ElectraNet and Murraylink's proposals.[627] If these

625 ESCOSA, *Email response to information request to the AER, Enquiry regarding average electricity bills*, 17 October 2012.
626 Based on a residential customer consuming approximately 5,000 kWh pa. ESCOSA, *1 July 2012 Electricity standing contract price adjustment*, June 2012, p. 2; ESCOSA, *Email response to information request to the AER, Enquiry regarding average electricity bills*, 17 October 2012.
627 Murraylink has a ten year regulatory control period (2013–23). This analysis is based on the first five years of the period, which coincides with ElectraNet's regulatory control period (2013–18).

lower transmission charges were pass through to end customers, a typical residential bill could be expected to reduce by $4 in total ($ nominal) during the 2013–18 regulatory control period. In comparison, ElectraNet's and Murraylink's proposals would result in an average residential bill increase of approximately $26 in total. Similarly, for an average South Australian non-residential customer bill of $3457 ($ nominal, excluding GST) in 2012–13, the AER's draft decision is not expected to contribute towards any price increase.[628] The AER estimates that if the lower transmission charges arising from its draft decision were pass through to end customers, a typical non-residential bill could be expected to reduce by $7 in total ($ nominal) during the 2013–18 regulatory control period. In comparison, ElectraNet's and Murraylink's proposals would result in an average non-residential bill increase of approximately $51 in total.

10.5 Revisions

Revision 10.1: the AER has determined ElectraNet's annual building block revenue requirement, X factor, annual expected MAR and the estimated total revenue cap over the 2013–18 regulatory control period as set out in table 10.1.

Revision 10.2: the AER has determined Electranet's annual adjustment process for the MAR over the 2013–18 regulatory control period as set out in section 10.3.1.

628 Based on a small business customer consuming approximately 10,000 kWh pa. ESCOSA, *1 July 2012 Electricity standing contract price adjustment*, June 2012, p. 2; ESCOSA, *Email response to information request to the AER, Enquiry regarding average electricity bills*, 17 October 2012.

11 Service target performance incentive scheme

This attachment sets out the Australian Energy Regulator's (AER) draft decision on ElectraNet's proposed parameter values and weightings for the service target performance incentive scheme (STPIS).[629] The structure of the STPIS has two components: a service component and a market impact component. This attachment deals with each component separately.

Service component

The service component of the AER's STPIS provides a financial incentive for transmission network service providers (TNSPs) to improve and maintain their service performance. This incentive counters the financial incentive under revenue regulation to reduce costs at the expense of service performance. A TNSP's performance is compared against the performance target for each parameter during the regulatory control period. The TNSP may receive a financial bonus for service improvements, or a financial penalty for declines in service performance. The financial bonus (or penalty) is limited to 1 per cent of the TNSP's maximum allowed revenue (MAR) for the relevant calendar year.

The AER must assess whether ElectraNet's proposed performance targets, caps, collars and weightings comply with the STPIS requirements for:[630]

- transmission circuit availability (with three availability sub–parameters)
  - transmission circuit availability
  - critical circuit availability peak
  - critical circuit availability non peak
- loss of supply event frequency (with two loss of supply event sub–parameters)
  - frequency of events where loss of supply exceeds 0.2 system minutes
  - frequency of events where loss of supply exceeds 0.05 system minutes
- average outage duration.

The AER must accept ElectraNet's proposed parameter values if they comply with the requirements of the STPIS.[631] The AER may reject them if it considers that they are inconsistent with the objectives of the STPIS.[632]

Market impact component

The market impact component provides financial rewards to TNSPs for improvements in its performance measure against a performance target. ElectraNet may earn an additional revenue increment of up to 2 per cent of its MAR for the relevant calendar year. Unlike the service component, there is no financial penalty associated with the market impact component.

629 The STPIS is established by clause 6A.7.4 of the NER.
630 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme, March 2011*, Appendix B, pp. 20–24.
631 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.3(a).
632 AER, *Final – Service target performance incentive scheme, March 2011,* clauses 3.3(m), 3.5(*e*) and 1.4.

The market impact parameter is defined as the number of dispatch intervals where an outage of a TNSP's network results in a network outage constraint with a marginal value of greater than $10/MWh (binding dispatch intervals).[633]

The STPIS requires ElectraNet to submit a performance target and cap for the market impact parameter.[634] It also requires that the proposed performance target be equal to the TNSP's average performance history over the past five years.[635] The AER must accept ElectraNet's proposed values if they comply with the requirements specified in clause 4.2 of the STPIS.[636] The AER may reject the proposed values if it forms the opinion that they are inconsistent with the objectives of the STPIS.[637]

The AER must decide on the performance target and the cap proposed by ElectraNet for the market impact parameter. The proposed cap must equal zero dispatch intervals.[638]

11.1 Draft decision

Service component

The AER does not accept ElectraNet's proposed service component STPIS parameter values and weightings as:

- they do not comply with the requirements in clauses 3.3 and 3.5 of the STPIS
- erroneous historical performance data was sued to calculate the targets, caps and collars in ElectraNet's revenue proposal.

Table 11.1 shows the AER's draft decision on ElectraNet's proposed service component parameter values and weightings.

633 AER, *Final – Service target performance incentive scheme, March 2011, Appendix C.*
634 AER, *Final – Service target performance incentive scheme, March 2011,* clause 4.2(a).
635 AER, *Final – Service target performance incentive scheme, March 2011,* clause 4.2(d).
636 AER, *Final – Service target performance incentive scheme, March 2011,* clause 4.2(a).
637 AER, *Final – Service target performance incentive scheme, March 2011,* clause 4.2(g).
638 AER, *Final – Service target performance incentive scheme, March 2011,* clause 4.2(c).

Table 11.1 AER draft decision on ElectraNet's parameter values and weightings for the service component of the STPIS

	Collar	Target	Cap	Weighting (% of MAR)
Transmission circuit availability (%)				
Transmission circuit availability	99.02	99.52	99.68	0.3
Critical circuit availability peak	97.36	99.12	99.96	0.1
Critical circuit availability non peak	98.25	99.37	99.87	0.0
Loss of supply event frequency (no. of events)				
> 0.05 system minutes	9	7	4	0.2
> 0.2 system minutes	4	2	0	0.2
Average outage duration (minutes)				
Average outage duration	323.2	203.2	83.2	0.2
Total weighting (% MAR)				1.0

Source: AER analysis.
Note: Subsequent to submitting its revenue proposal, ElectraNet resubmitted its STPIS data.

Market impact component

The AER does not accept ElectraNet's proposed market impact component STPIS parameter values as the AER identified several errors in ElectraNet's calculation. Table 11.2 shows the AER's draft decision on ElectraNet's proposed market impact component target and cap.

Table 11.2 AER draft decision on ElectraNet's parameter values and weightings for the market impact component of the STPIS

	Target	Cap	Weighting (% of MAR)
Market impact parameter (dispatch intervals)	1585	0	2.0

Source: AER analysis.

11.2 ElectraNet's proposal

Service component

ElectraNet submitted that its performance against the STPIS exhibited an overall trend of high performance, with ElectraNet operating at, or near, 'best practice' levels for a network with its characteristics.[639] The only parameter it did not perform well against was the 'average outage duration' parameter. ElectraNet submitted that low probability, high impact outages caused this poor performance.[640]

639 ElectraNet, *Revenue proposal*, pp. 44–45 and p. 49.
640 ElectraNet, *Revenue proposal*, pp. 47–48.

ElectraNet proposed the following:

- a reduction in the weighting of the 'critical circuit availability – peak' sub–parameter and an increase in the weighting of the 'average outage duration' parameter[641]
- adjustments to the performance targets for the three availability sub–parameters ('transmission circuit availability', 'critical circuit availability – peak' and 'critical circuit availability – non peak' sub–parameters) to account for the volume of capital works in the 2013–18 regulatory control period[642]
- exclusion of outages associated with triggered contingent projects during the 2013–18 regulatory control period[643]
- changes to the distributions used to calculate the caps and collars for all parameters[644]
- performance targets that were set on the average performance of the last five years.[645]

In its revenue proposal, ElectraNet submitted STPIS parameter values that were not calculated from the data annually reviewed by the AER. ElectraNet subsequently resubmitted its STPIS parameter values calculated from the data annually reviewed by the AER.[646] The AER's analysis and draft decision is based on the resubmitted data rather than the data provided in ElectraNet's revenue proposal.

Table 11.3 sets out ElectraNet's proposed performance targets, caps, collars and weightings for each parameter under the service component of the STPIS, as resubmitted and based on the data annually reviewed by the AER.

Table 11.3 ElectraNet's proposed parameter values and weightings for the service component of the STPIS

Parameter	Collar	Target	Cap	Weighting (% of MAR)
Transmission circuit availability (%)				
Transmission circuit availability	**99.02**	**99.46**	**99.68**	**0.3**
Critical circuit availability peak	**97.36**	**99.09**	**99.96**	**0.1**
Critical circuit availability non peak	**98.25**	**99.33**	**99.87**	**0.0**
Loss of supply event frequency (no. of events)				
> 0.05 system minutes	**9**	**7**	**4**	**0.1**
> 0.2 system minutes	**4**	**2**	**0**	**0.2**
Average outage duration (minutes)				
Average outage duration	**323.2**	**203.2**	**83.2**	**0.3**
Total				**1.0**

Source: ElectraNet, *Email response to information request AER RP 027*, ENET253, 6 September 2012.

641 ElectraNet, *Revenue proposal*, pp. 139–140.
642 ElectraNet, *Revenue proposal*, pp. 134–135.
643 ElectraNet, *Revenue proposal*, p. 135.
644 ElectraNet, *Revenue proposal*, pp. 137–138.
645 ElectraNet, *Revenue proposal*, p. 134.
646 ElectraNet, *Email response to information request AER RP 027*, ENET253, 6 September 2012.

Market impact component

ElectraNet proposed a performance target of 1588 dispatch intervals as its average performance history from 2007–2011.[647] Table 11.4 sets out ElectraNet's proposed parameter values and weighting for the market impact component.

Table 11.4 ElectraNet's proposed parameter values and weightings for the market impact component of the STPIS

	Target	Cap	Weighting (% of MAR)
Market impact parameter (dispatch intervals)	1588	0	2.0

Source: ElectraNet, *Revenue proposal*, p. 140.

11.3 Assessment approach

Service component

The AER assessed ElectraNet's proposal against the requirements of the STPIS — that is, whether:

1. ElectraNet's data recording systems and processes produce accurate and reliable data and whether the data is recorded consistently based on the parameter definitions under the STPIS[648]
2. the proposed performance targets equal the average of the most recent five years performance data[649]
3. any adjustments to the proposed targets are warranted and reasonable[650]
4. ElectraNet used a sound methodology, with reference to the performance target, to calculate the proposed caps and collars[651]
5. any adjustment to the performance target of a parameter was also applied to the cap and collar of that parameter[652]
6. ElectraNet demonstrated the proposed weightings are consistent with the objectives of the STPIS[653]
7. ElectraNet accounted for the factors listed in the STPIS when proposing each parameter's weighting. In particular, the AER considers the proposed weightings should reflect:[654]
   - the importance of the parameter and sub–parameter in the reliability of ElectraNet's transmission network
   - the scope for further performance improvement against the parameter
   - the extent to which the parameters and sub–parameters applying to ElectraNet overlap.

647 ElectraNet, *Revenue proposal*, p. 140.
648 AER, *Final – Service target performance incentive scheme, March 2011,* clauses 3.3(d) and 3.3(g).
649 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.3(g).
650 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.3(k).
651 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.3(e).
652 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.3(e).
653 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.5(a).
654 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.5(d).

8. the sum of the weightings equals the maximum revenue increment or decrement (1 per cent of maximum allowed revenue (MAR))[655]

9. any of the proposed weightings are inconsistent with the objectives of the scheme.[656] In particular, the AER considers a proposed weighting should be rejected if it:

    - does not provide any incentive for ElectraNet to maintain and improve reliability for its customers

    - does not assist in setting efficient capital and operating expenditure allowances by balancing ElectraNet's incentive to reduce actual expenditure with the need to maintain and improve transmission system reliability for its customers.

Market impact component

Sources of data

To calculate both a TNSP's performance measure and performance target, the AER allocates each network constraint to the TNSP responsible for the constraint using:

- the Market Information on Planned Network Outages, which is published every month by the Australian Energy Market Operator (AEMO) based on information provided by TNSPs
- the Network Outage Schedule, which is published by AEMO on its website based on information provided by TNSPs
- the description of the constraint ID published by AEMO or
- where it is not clear from (1), (2) or (3), the published market management system data or other information provided by AEMO.

Where the information described in (1), (2), (3) or (4) indicates that more than one TNSP is responsible for a single network outage constraint (for example an outage affecting an interconnector), the number of dispatch intervals is apportioned equally between the TNSPs.

Market management system data

According to the definition of the market impact parameter, the marginal value of a constraint is an indication of the change, at the margin, in the cost of producing electricity sufficient to meet demand brought about by a particular network outage constraint.

When the STPIS was first introduced, AEMO published the marginal value of constraints within the market management system (MMS) database table called 'dispatchconstraint'. This table displays all marginal values as absolute values (ie no negative values appear).

In May 2009, AEMO began publishing the MMS database table 'mcc_constraintsolution'. The outputs of this table are produced by re–running the dispatch engine to relax violated constraints that appear in the 'dispatchconstraint' table. The marginal values produced by the 'mcc_constraintsolution' table are considered to be a better reflection of the true marginal value of the constraints. AEMO did not absolute the values in this table as they did for the 'dispatchconstraint' table. The 'mcc_constraintsolution' table contains both positive and negative marginal values.

655 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.5(b).
656 AER, *Final – Service target performance incentive scheme, March 2011,* clause1.4.

The AER has advised all TNSPs subject to the market impact parameter that 'mcc_constraintsolution' data should be used whenever available for the purposes of measuring performance and calculating the performance target. The TNSPs should convert all values in the tables to absolute values before submission or otherwise ensure marginal values greater than $10/MWh or less than -$10/MWh should be submitted. All TNSPs agrees with the approach and have submitted the data accordingly. For this reason, marginal values less than –$10/MWh are included when assessing the market impact parameter.

11.4 Reasons for draft decision

Service component

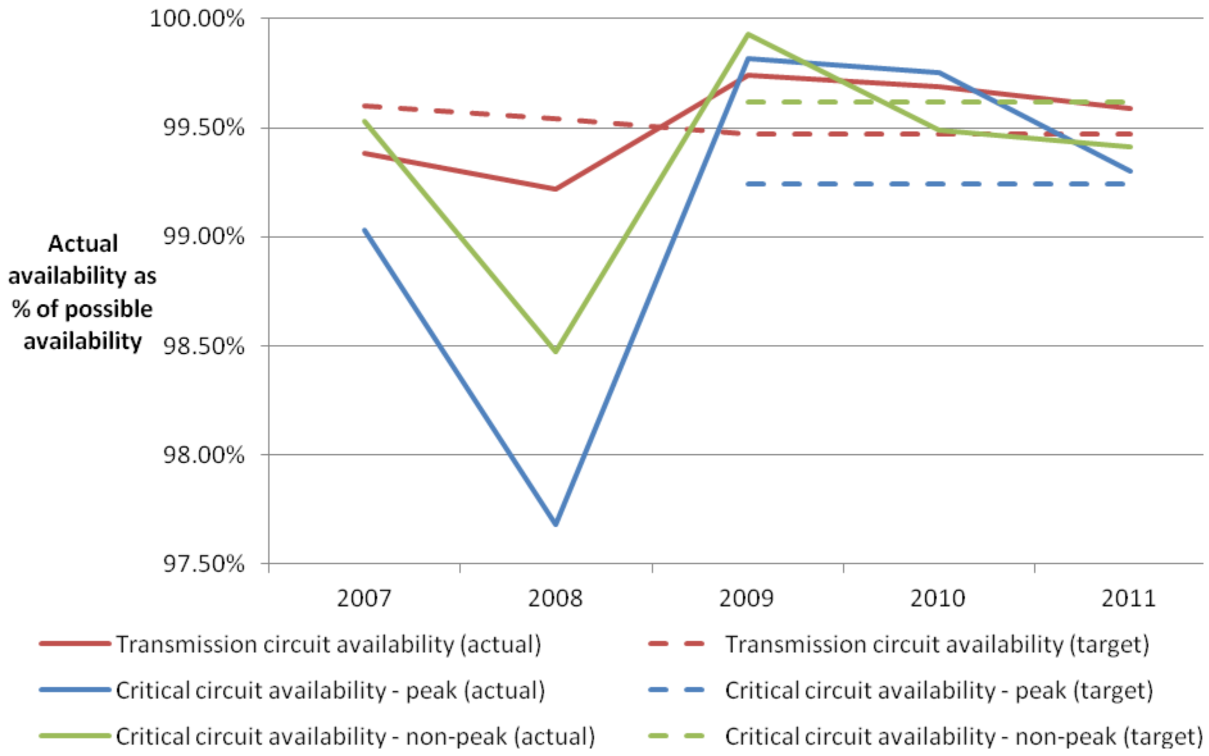
The AER does not accept ElectraNet's proposed service standard parameter values and weightings because:

- erroneous historical performance data was sued to calculate the targets, caps and collars in ElectraNet's revenue proposal
- the proposed service component parameter weightings do not satisfy clause 3.5 of the STPIS and have not been sufficiently justified
- the methodology used to adjust performance targets for forecast capex volumes is inappropriate
- the exclusion of outages associated with contingent projects is not allowed under the STPIS.[657]

The following figures show ElectraNet's performance against the service component parameters from 2007 to 2011.

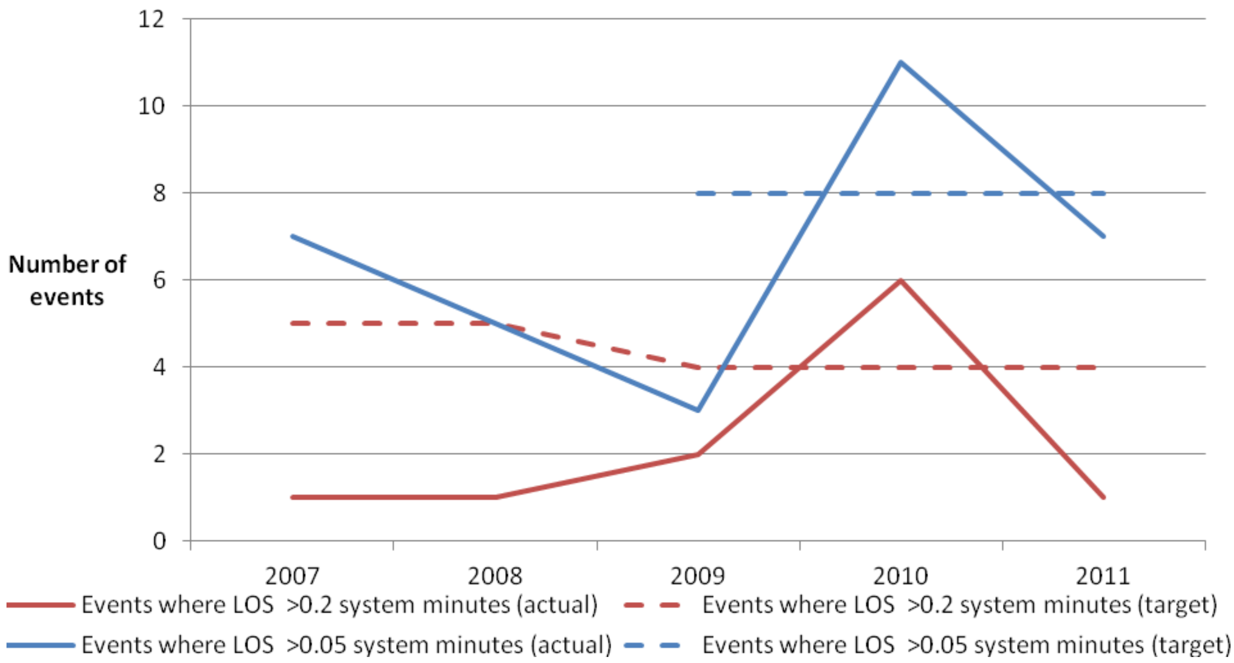
[657] AER, *Final –Service target performance incentive scheme, March 2011,* clause 3.2.

Figure 11.1 ElectraNet's circuit availability performance over the past five years



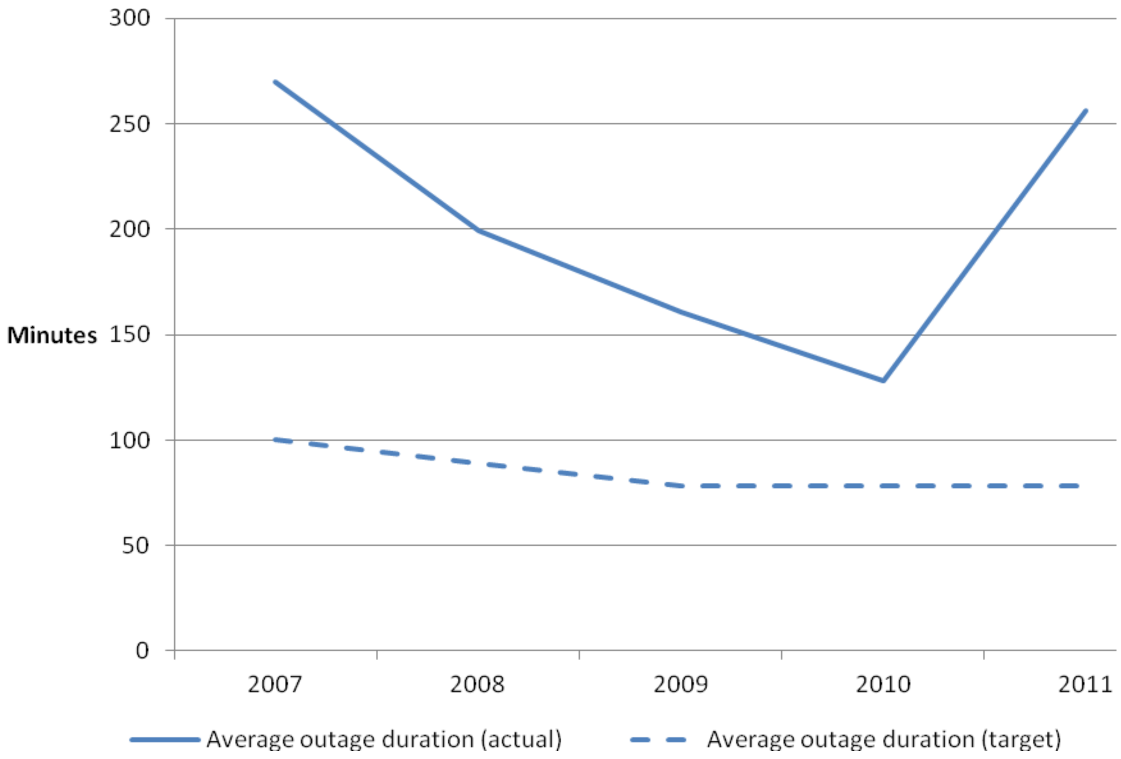
Source: AER analysis; ElectraNet, *Email response to EMCa/060, STPIS data reconciliation*, *ENET232*, 17 August 2012.

Figure 11.2 ElectraNet's loss of supply event performance over the past five years



Source: AER analysis; ElectraNet, *Email response to EMCa/060, STPIS data reconciliation, ENET232*, 17 August 2012.

Figure 11.3 ElectraNet's average outage duration performance over the past five years



Source: AER analysis; ElectraNet, *Email response to EMCa/060, STPIS reconciliation, ENET232*, 17 August 2012.

ElectraNet performed well against most performance measures during the past five years. Performance against the 'transmission circuit availability' and 'critical circuit availability – peak' sub–parameters was near or above the cap for the past three years. Further, ElectraNet performed better than the target against the loss of supply sub–parameters for four of the last five years.

ElectraNet submitted that limited opportunities exist for further service improvements and recognition should be given to the inherent difficulty of improving from a high base.[658] While recognising ElectraNet's current performance, the AER considers that the STPIS should provide ongoing incentives not just to improve performance but also to maintain performance. For this reason, the STPIS applying to ElectraNet in the 2013–18 regulatory control period should provide incentives for:

- ElectraNet to improve performance against parameters where improvements can reasonably be made; and
- to maintain performance against parameters where opportunities for improvement are limited and/or where performance is at a high level.

This approach promotes the long term interests of consumers by encouraging TNSPs to improve and maintain the quality and reliability of supply of electricity, consistent with the National Electricity Objective (NEO), the STPIS principles in the NER[659] and the objectives of the STPIS. [660] The AER therefore considered ElectraNet's STPIS proposal in the context of both improving and maintaining performance.

658 ElectraNet, *Revenue proposal*, p. 131.
659 NER, clause 6A.7.4.
660 NEL, section 7; AER, *Final – Service target performance incentive scheme,* March 2011, clause 1.4.

11.4.1 Weightings for service component parameters

The AER does not accept ElectraNet's proposed weightings for the 'loss of supply event > 0.05 system minutes' sub–parameter and the 'average outage duration' parameter. The AER accepts ElectraNet's proposed weightings for all other sub–parameters.

The STPIS requires ElectraNet to propose weightings for each parameter and demonstrate how the proposed weightings are consistent with the objectives of the scheme.[661] ElectraNet proposed to reduce the weighting applied to the 'critical circuit availability – peak' sub–parameter while increasing the weighting applied to the 'average outage duration' sub–parameter. ElectraNet did not propose changes to the weightings for any other sub–parameter.[662] As part of this, ElectraNet considered it appropriate to maintain a zero weighting for the 'critical circuit availability – non peak' sub–parameter.[663]

Critical circuit availability – non peak sub–parameter

The AER accepts ElectraNet's proposal to maintain a zero weighting on the 'critical circuit availability – non peak' sub–parameter.

Applying a zero weighting to the 'critical circuit availability – non peak' sub–parameter incentivises the shifting of outages from peak to non peak times. Additionally, applying a weighting would reduce the weighting applied to other parameters decreasing the incentive to improve and maintain performance against those parameters. This accords with ElectraNet's proposal to maintain a zero weighting for the 'critical circuit availability – non peak' sub–parameter.

Critical circuit availability – peak sub–parameter

The AER accepts ElectraNet's proposed reduction in the weighting for the 'critical circuit availability – peak' sub–parameter.

When the 'critical circuit availability – peak' sub–parameter was introduced, it was partly aimed at improving and maintaining reliability of those elements of the transmission network that most affect spot prices.[664] In March 2008, the AER introduced the market impact component to the STPIS.[665] The market impact component directly incentivises TNSPs to minimise the market impact of their outages. The introduction of the market impact component has reduced the need for the 'critical circuit availability – peak' parameter to incentivise reliability on elements that affect the spot price. As such, the 'critical circuit availability – peak' parameter's relative importance in the reliability of ElectraNet's network has decreased. A decrease in its weighting is therefore appropriate.

However, the AER still considers the 'critical circuit availability – peak' sub–parameter to be relevant. As noted in the AER's final decision on the STPIS, circuit availability acts as a leading indicator of reliability. If availability is low then reliability may be affected in future periods.[666] As such, the AER considers that a non–zero weighting for 'critical circuit availability – peak' sub–parameter is still appropriate. The AER therefore accepts ElectraNet's proposal to decrease the weighting on the 'critical circuit availability – peak' sub–parameter from 0.2 per cent of MAR to 0.1 per cent of MAR.

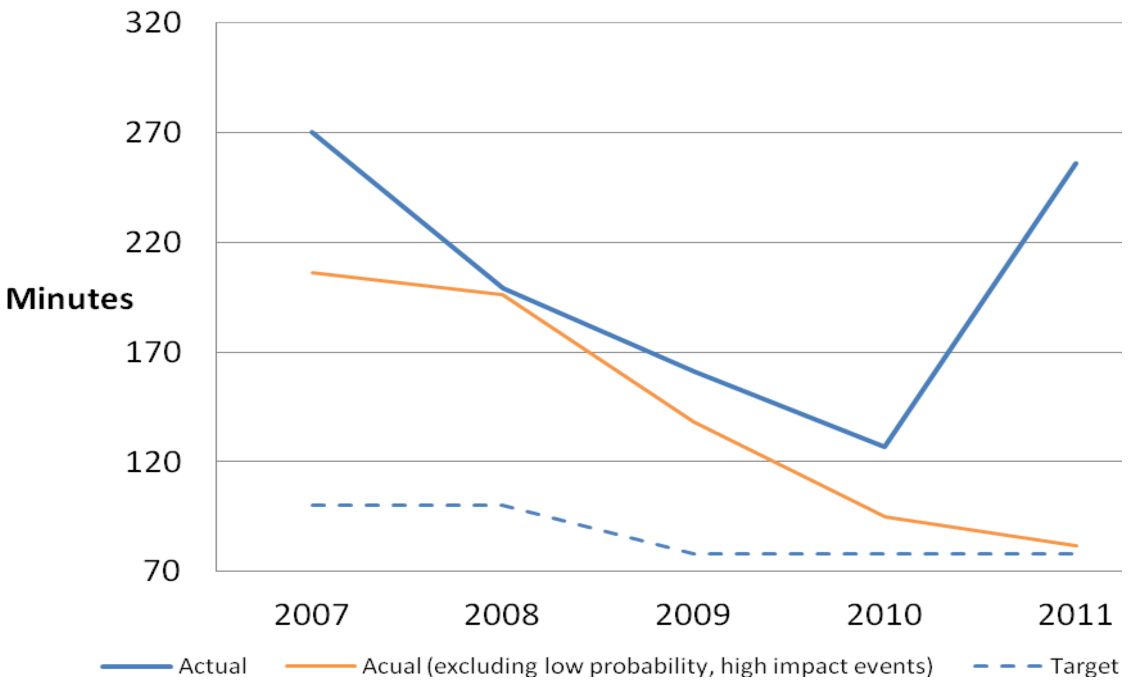
661 AER, *Final – Service target performance incentive scheme,* March 2011, clauses 3.5(b) and 1.4.
662 ElectraNet, *Revenue proposal*, pp. 139–140.
663 ElectraNet, *Revenue proposal*, p. 140.
664 AER, *Final decision – Electricity transmission network service providers, Service target performance incentive scheme, August 2007,* pp. 4–5. It also aims to incentivise improved performance at times when high levels of performance are most valued by customers. Availability in general is also a lead indicator of reliability.
665 AER, *Final decision – Electricity transmission network service providers, Service target performance incentive scheme (incorporating incentives based on the market impact of transmission congestion),* March 2008.
666 AER, *Final decision – Service target performance incentive scheme*, March 2011, p. 7.

Average outage duration parameter

The AER does not accept ElectraNet's proposal to increase the weighting on the 'average outage duration' parameter. ElectraNet reasoned that there was merit in increasing the weighting from 0.2 per cent to 0.3 per cent of MAR to recognise concerns some stakeholders may have about ElectraNet's 'average outage duration' performance.[667]

While ElectraNet's performance has been adversely impacted by low probability, high impact events on the radial network, the underlying trend shows a positive response to the current incentives provided by the 'average outage duration' parameter.[668] Figure 11.4 shows that ElectraNet's 'average outage duration' performance has actually improved when the effects of low probability, high impact events are removed.[669]

Figure 11.4 Average outage duration performance including and excluding high impact, low probability events



Source: ElectraNet, *Email response to information request EMCa/004, TR STPIS methodology and systems*, 22 June 2012 and AER analysis.

The AER considers that ElectraNet's performance excluding low probability high impact events during the 2008–13 regulatory control period should allay any stakeholder concerns. The AER also notes that due to ElectraNet's performance during the 2008–13 regulatory control period, the 'average outage duration' target and cap will be easier to achieve.[670]

The AER's consultant, EMCa, noted that ElectraNet's poor historic performance against the 'average outage duration' parameter was caused by a number of low probability, high impact events. Therefore, a strong probability exists that ElectraNet's 'average outage duration' performance will

667 ElectraNet, *Revenue proposal*, p. 139.
668 ElectraNet, *Email response to information request EMCa/004, TR STPIS methodology and systems*, 22 June 2012.
669 ElectraNet, *Email response to information request EMCa/004, TR STPIS methodology and systems*, 22 June 2012, p. 3.
670 This is because, in accordance with clause 3.3(g) of the STPIS, performance targets are based on the average of the past five years performance history.

improve in the 2013–18 regulatory control period with no additional effort from ElectraNet. In such circumstances, EMCa also considered that it was inappropriate to increase the weighting and noted that it was unable to find evidence of any capex or opex proposals directly related to improving performance on the radial network.[671]

For these reasons, the current weighting provides a sufficient incentive for ElectraNet to improve and maintain its 'average outage duration' performance during the 2013–18 regulatory control period. Further, ElectraNet has not demonstrated how the increased weighting is consistent with the objectives listed in clause 1.4 of the STPIS.[672]

Loss of supply events >0.05 system minutes sub–parameter

ElectraNet did not propose a change to the weighting for the 'loss of suppy events > 0.05 system minutes' sub–parameter. However, the AER considers that additional weighting should be applied. The AER considers that an equal weighting should apply to the two loss of supply sub–parameters. Each loss of supply sub–parameter incentivises desirable behaviour and, given the 'x' and 'y' system minute thresholds are set appropriately, equal weightings should apply. EMCa considered the STPIS should apply greater weight to service parameters that incentivise the management of total unplanned availability and unplanned service interruptions.[673] Additional weight should therefore be given to the 'loss of supply events >0.05 system minutes' sub–parameter. The AER agrees with this principle, and considers that additional weighting will help improve and maintain performance against this sub–parameter. The AER therefore considers it appropriate to increase the weighting applied to the 'loss of supply events > 0.05 system minutes' sub–parameter from 0.1 per cent to 0.2 per cent of MAR.

11.4.2 Adjustments to reliability targets for proposed capital works

The STPIS permits proposed performance targets to be adjusted for, amongst other things, the expected effects on performance from any increases or decreases in the volume of planned capital works.[674] ElectraNet proposed to adjust the three availability parameter targets, caps and collars to allow for the increase in volume and composition of forecast capital works proposed for the 2013–18 regulatory control period.[675]

The AER does not accept ElectraNet's proposal to adjust the three availability parameter targets for an increase in the volume of capital works. The AER has previously accepted adjustments for an increase in the volume of capital works in other determinations. However, these were bottom up assessments of the estimated outage hours associated with each proposed capex project.[676] ElectraNet applied a top down method, determining a dollar per outage hour ratio ($/hr) for the 2007–11 data. It then applied this ratio to the dollar value of proposed capital works to estimate the capex related outage hours in the 2013–18 regulatory control period.[677] The AER considers this methodology makes an inappropriate assumption about the relationship between the dollar value of a capex project and the outage hours associated with that project. High cost capex projects may have few associated outage hours and likewise low value capex projects may have many associated outage hours. As such, ElectraNet's proposed adjustment is likely to be inaccurate.

671 EMCa, *ElectraNet technical review*, October 2012, p. 166.
672 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme,* March 2011, clause 3.5(a).
673 EMCa, *ElectraNet technical review*, October 2012, p. 167.
674 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme, March 2011,* clause 3.3(k)(2).
675 ElectraNet, *Revenue proposal*, pp. 134–135.
676 AER, *Draft decision, TransGrid transmission determination 2009–10 to 2013–14*, October 2008, p. 170; AER, *Draft decision, Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 288–289.
677 ElectraNet, *Revenue proposal, Appendix Y – STPIS capex adjustment*, pp. 4–5.

EMCa also considered that the outage hours associated with capital works can vary significantly depending on the type of work. EMCa concluded that, unless the content of work for the 2013–18 regulatory control period and the 2008–13 regulatory control period are approximately the same, the methodology is unrefined and can produce erroneous results.[678] EMCa considered mapping each category of work individually to be more accurate than using a composite average.[679] For these reasons, EMCa concluded that ElectraNet's methodology was inappropriate.

The AER does not accept ElectraNet's proposed methodology of adjusting the proposed targets for the three availability sub–parameters for the volume of capital works. The AER therefore does not accept ElectraNet's proposed top down adjustment to transmission circuit availability targets for the increased volume of capital works.

11.4.3 Exclusion of outages associated with contingent projects

The AER does not accept ElectraNet's proposal to exclude outages associated with any contingent projects triggered during the 2013–18 regulatory control period.[680] ElectraNet also stated that, if the AER considered that outages associated with contingent projects should be included, then it reserved the right to propose adjustments to the three availability sub–parameter targets.[681] The AER does not accept this proposal.

Clause 3.2 of the STPIS states that Appendix B of the STPIS may require that an element relating to a parameter, such as exclusions, is to be established in the transmission determination. However, this must be explicitly stated in Appendix B.[682] Appendix B of the STPIS does not explicitly state that exclusions are to be established in ElectraNet's transmission determination.[683] As such, additional exclusions cannot be established in ElectraNet's transmission determination.

The AER also considers that ex ante adjustments to STPIS targets for contingent projects are inappropriate. The STPIS allows reasonable adjustments to proposed targets to allow for:[684]

> the expected effects on the TNSP's performance from any increases or decreases in the volume of capital works planned during the regulatory control period...

Contingent projects are uncertain in their nature and timing, and cannot be said to be 'planned capital works'. As such, adjusting for contingent projects in a TNSP's revenue proposal is not permitted by the scheme. It would be extremely difficult (if not impossible) to calculate an appropriate adjustment when it is unknown whether the project will occur during the regulatory control period.[685] For these reasons, the AER does not accept ElectraNet's proposal to adjust transmission circuit availability targets for triggered contingent projects.

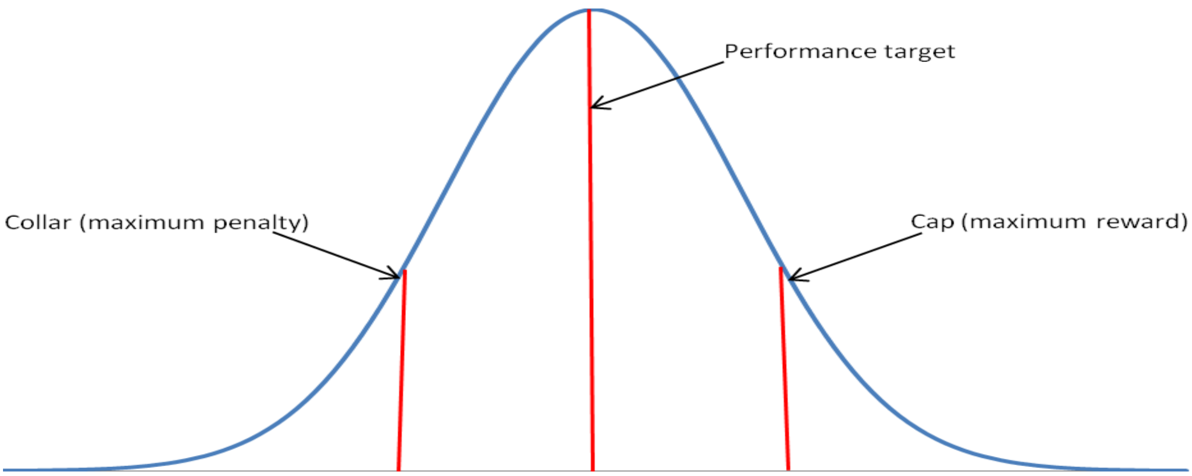
11.4.4 Caps and collars

The AER accepts ElectraNet's proposed cap and collar values. While the AER does not consider that ElectraNet's method of deriving the caps and collars is conceptually sound, the AER values derived from a conceptually sound approach are not materially different from ElectraNet's proposed values. As such, the AER considers ElectraNet's proposed cap and collar values to be appropriate.

678 EMCa, *ElectraNet technical review*, October 2012, p. 165.
679 EMCa, *ElectraNet technical review*, October 2012, p. 166.
680 ElectraNet, *Revenue proposal*, p. 135.
681 ElectraNet, *Revenue proposal*, p. 135.
682 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.2.
683 AER, *Final – Service target performance incentive scheme, March 2011, Appendix B, p. 20–24.*
684 AER, *Final – Service target performance incentive scheme, March 2011,* clause 3.3(k)(2).
685 AER, *Final decision – Electricity transmission network service providers, Service target performance incentive scheme*, August 2007, p. 9.

Proposed caps and collars must be calculated with reference to the proposed performance targets using a sound methodology.[686] The AER has generally accepted an approach where five years of performance data is used to derive a statistical distribution, with the caps and collars set at two standard deviations either side of the mean (if using a normal distribution), or at the 5th and 95th percentiles (if using an asymmetric distribution). This is termed a 'symmetric incentive' as the caps and collars are set at the same number of standard deviations from the mean of the distribution.[687] The AER has also previously accepted caps set one standard deviation above the mean (with a collar set two standard deviations below the mean) for transmission circuit availability sub–parameters. This is termed an 'asymmetric incentive' as the cap is set closer to the mean of the distribution than the collar. This approach was applied to availability parameters when the application of two standard deviations above the mean resulted in a cap greater than 100 per cent availability.[688] This approach is illustrated in the figure below.

Figure 11.5 Using a distribution to derive cap and collar values



Note: This shows how caps and collars are set using a normal distribution (symmetrical distribution). Asymmetrical distributions can also be used to set cap and collar values.

Distributions used to calculate caps and collars

ElectraNet proposed changing the distributions used to derive the caps and collars. Table 11.5 shows the distributions that were used to calculate the caps and collars for the 2008–13 regulatory control period and the distributions proposed by ElectraNet to calculate the caps and collars for the 2013–18 regulatory control period.

686 AER, *Final – Service target performance incentive scheme,* March 2011, clause 3.3(e).

687 AER, *Final – Service target performance incentive scheme,* March 2011, clause 3.3(f).

688 AER, *Draft decision, Transend transmission determination 2009–10 to 2013–14*, November 2008, p. 223; AER, *Draft decision, SP AusNet transmission determination 2008–09 to 2013–14*, August 2007, pp. 207–208.

Table 11.5 ElectraNet's historical and proposed distributions used to calculate caps and collars

	Current			Proposed		
	Distribution	Cap (std dev from mean)	Collar (std dev from mean)	Distribution	Cap (std dev from mean)	Collar (std dev from mean)
Transmission circuit availability	Weibull	5% level	95% level	Normal	One	Two
Critical circuit availability – peak	Weibull	5% level	95% level	Normal	One	Two
Critical circuit availability – non peak	Weibull	5% level	95% level	Normal	One	Two
Loss of supply events > 0.05 system minutes	Chi–squared	One, to the nearest integer	One, to the nearest integer	Logistic	One, to the nearest integer	One, to the nearest integer
Loss of supply events > 0.2 system minutes	Chi–squared	One, to the nearest integer	One, to the nearest integer	Logistic	One, to the nearest integer	One, to the nearest integer
Average outage duration	Weibull	5% level	95% level	Normal	Two	Two

Source: ElectraNet, *Revenue proposal*, p. 138.

The AER considers the distribution selected to calculate the caps and collars for a particular parameter must be conceptually sound. ElectraNet's application of a normal distribution to the three availability sub–parameters, which implies that values above 100 per cent availability are reasonably likely, is not conceptually sound.[689] This is because availability values in excess of 100 per cent are impossible in practice.[690] Further, ElectraNet's use of a normal distribution for the three availability sub–parameters does not take account of the inherent skewness of the availability data. The AER accounted for the inherent skewness of availability data by using an asymmetric distribution in ElectraNet's previous transmission determination.[691] That approach should be maintained.

A discrete distribution, such as the Poisson distribution, should be used for the loss of supply parameters. This is because the occurrence of loss of supply events are discrete values, not continuous like circuit availability values. The AER considers that ElectraNet's use of a normal distribution for the average outage duration parameter is conceptually sound given that its use does not imply values lower than zero system minutes are reasonably likely. The AER considered EMCa's advice in forming its views on the distributions to use to calculate ElectraNet's caps and collars.

EMCa considered that the distributions proposed by ElectraNet for the availability and loss of supply parameters were inappropriate. EMCa stated that the use of a normal distribution implies that values greater than 100 per cent are reasonably likely. However, this is impossible because availability cannot be greater than 100 per cent. Further, the normal distribution does not reflect the skewed distribution of availability data due to the absolute bound on availability at 100 per cent. EMCa

689 ElectraNet, *Revenue proposal*, Appendix Z, Parsons Brinckerhoff, Fitting probability distributions to reliability data for calculation of STPIS values, 29 May 2012, pp. 2–4.

690 ElectraNet, *Revenue proposal*, Appendix Z, Parsons Brinckerhoff, Fitting probability distributions to reliability data for calculation of STPIS values, 29 May 2012.

691 AER, *Draft decision, ElectraNet transmission determination 2008–09 to 2012–13*, November 2007, pp. 199–200.

considered an asymmetric distribution should be used to derive the caps and collars for the three availability sub–parameters.

EMCa also noted that ElectraNet has derived the caps and collars for the loss of supply event sub–parameters using a process which fitted a continuous distribution (the logistic distribution) to discrete events. EMCa noted that this approach may be appropriate where a large number of data points are available. However, EMCa considered this approach inappropriate in this case because of the low number of loss of supply events.[692]

Setting cap and collar values

Availability sub–parameters caps and collars

Using a normal distribution, ElectraNet proposed a cap one standard deviation above the mean and a collar two standard deviations below the mean for the three availability parameters. This is an asymmetric incentive under the scheme.[693]

The AER considers an asymmetric distribution for the three availability sub–parameters, better reflects the skewness of ElectraNet's transmission circuit availability data. The use of an asymmetric distribution results in a cap that can be set at the 95th percentile (the equivalent of two standard deviations above the mean).[694] This means that a symmetric incentive could be implemented if an asymmetric distribution was used to calculated the caps and collars for ElectraNet's three availability sub–parameters.

The Energy Consumers Coalition of South Australia (ECCSA) considered that the caps and collars for the three availability sub–parameters should be symmetrical.[695] However, service performance improvements become harder to obtain when a TNSP approaches 100 per cent availability. As such, a cap set at the 85th percentile (the equivalent of one standard deviation above the mean for asymmetric distributions) may be appropriate to reward TNSPs for service improvements when they are already performing at a high level.[696]

Further, the AER does not consider it desirable to set a collar at the 15th percentile (the equivalent of one standard deviation below the mean for an asymmetric distribution). If the collar was set at the 15th percentile, the TNSP would receive the maximum penalty once performance degraded to the 15th percentile level. There would then be no incentive for the TNSP to prevent or mitigate events that would further affect service performance. A collar set at the 5th percentile (or two standard deviations from the mean) provides an incentive to prevent or mitigate events when performance has degraded below the 15th percentile level, as the TNSP may still be able to avoid the maximum penalty. A collar set at the 5th percentile also means that a TNSP is not unduly penalised for natural variability in annual performance and events that may, to some degree, be out of the TNSP's control. As such, the AER considers it appropriate to set a collar at the 5th percentile or two standard deviations below the mean.

[692] EMCa, *ElectraNet technical review*, October 2012, p. 164.
[693] AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme,* March 2011, clause 3.3(f).
[694] ElectraNet, *Email response to information request AER 29, Parson Brinckerhoff, Fitting Probability Distributions to reliability data for calculation of STPIS values, Report 2, ENET 260*, 27 September 2012.
[695] ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 52.
[696] It should be noted that, using an asymmetric distribution, the AER was able to set the cap at the 95th percentile. This then made a symmetrical incentive. However, the AER considers that the difference between ElectraNet's proposed cap and collar values and those calculated using the AER's method are immaterially different. As such, the AER has accepted ElectraNet's proposed cap and collar values.

Modelling of cap and collar values

The AER sent the principles outlined above to ElectraNet and requested that ElectraNet use these principles to recalculate its caps and collars. Table 11.6 shows ElectraNet's proposed cap and collar values compared to the values calculated using the AER's method.

Table 11.6 Comparison of ElectraNet's proposed cap and collar values with the AER's alternative cap and collar values

	Proposed values		Alternative values	
	Collar	**Cap**	**Collar**	**Cap**
Transmission circuit availability (%)	99.02	99.68	99.06	99.92
Critical circuit availability – peak (%)	97.36	99.96	97.05	99.75
Critical circuit availability – non peak (%)	98.25	99.87	98.03	99.85
Loss of supply events > 0.05 system minutes	9	4	9	4
Loss of supply events > 0.2 system minutes	4	0	4	1
Average outage duration (minutes)	323.2	83.2	321.2	78.8

Source: ElectraNet, *Email response to information request AER 29, Parson Brinckerhoff, Fitting Probability Distributions to reliability data for calculation of STPIS values, Report 2, ENET 260*, 27 September 2012.

The AER considers that there is an immaterial difference between ElectraNet's revenue proposal values and the values calculated in accordance with the AER's method. Some values increase slightly (for example, the 'transmission circuit availability' sub–parameter cap) and other values decrease slightly (for example the 'loss of supply events > 0.05 system minutes' sub parameter cap). The AER's method does not result in materially different cap and collar values and therefore does not result in a materially different incentive that furthers the objectives of the STPIS and NER any better than ElectraNet's proposed values. The AER therefore accepts ElectraNet's proposed cap and collar values.

11.4.5 Setting performance targets

In its revenue proposal, ElectraNet submitted STPIS parameters that were not calculated from the data annually reviewed by the AER. ElectraNet subsequently resubmitted its STPIS parameter values, calculated from the data annually reviewed by the AER. The AER therefore does not accept the performance targets proposed by ElectraNet in its revenue proposal. The AER has calculated the performance targets using the arithmetic average of the past five years data, as reviewed by the AER.

Performance targets must equal the TNSP's average performance history over the past five years.[697] The AER has generally approved performance targets that are the arithmetic mean of the past five

[697] AER, *Final decision – Service target performance incentive scheme*, August 2007, clause 3.3(g).

years' performance data. ElectraNet followed this approach for its proposed performance targets. The AER accepts this approach.

EMCa noted that the term 'average' in statistics can be also used to describe the mean, median, mode or 50th percentile of a data set. ElectraNet calculated its performance targets using the arithmetic mean of the past five years' performance data. EMCa considered this appropriate when using a normal distribution to calculate caps and collars. However, EMCa recommended that an asymmetric, rather than a normal distribution, should be used for ElectraNet's service standard parameters. Given this, it considered the 50th percentile was the most appropriate average to use to set the performance targets. This is because the 50th percentile is the measure of a mid–point that is directly related to the caps and collars. The arithmetic average is not directly related to the caps and collars when using an asymmetric distribution.[698]

The AER notes EMCa's comments about the term 'average performance history over the most recent five years'' in the STPIS. While the AER accepts that other statistical measures may be referred to as a measure of the 'average' of a data set, the AER considers that the ordinary meaning of the term 'average' is the arithmetic mean or simple average. This is consistent with the AER's interpretation of the term in previous transmission determinations.

The AER also notes that using the arithmetic average to determine the performance target may result in caps and collars that are not calculated with direct reference to that target. However, the AER considers that using the arithmetic average, rather than the 50th percentile, to set the performance target results in an immaterial difference. Table 11.7 shows the outcomes of using an arithmetic average or the 50th percentile to set the performance targets.

Table 11.7 Difference between using arithmetic average and 50th percentile to set ElectraNet's performance targets

Parameter	Arithmetic average	50th percentile	Difference
Transmission circuit availability (%)	99.52	99.49	.03
Critical circuit availability – peak (%)	99.12	98.85	0.27
Critical circuit availability – non peak (%)	99.37	99.24	0.13
Loss of supply events > 0.05 system minutes	2.2	2.2	0
Loss of supply events > 0.2 system minutes	6.6	6.6	0
Average outage duration (minutes)	203.2	200.0	3.2

Source: ElectraNet, *Email response to information request AER 29, Parson Brinckerhoff, Fitting Probability Distributions to reliability data for calculation of STPIS values, Report 2, ENET 260*, 27 September 2012.

This illustrates that using an arithmetic average rather than the 50th percentile of the distribution selected to calculate the caps and collars does not result in a material difference to the performance targets that will apply to Electranet for the 2013–18 regulatory control period. While the AER sees merit in using the 50th percentile, it does not consider that the use of the arithmetic average results in

698 EMCa, *ElectraNet technical review*, October 2012, pp. 164–165.

unreasonable performance targets that will apply to ElectraNet in the 2013–18 regulatory control period. As such, the AER has set ElectraNet's performance targets equal to the arithmetic average of the past five years performance history.

ECCSA and the Energy Users Association of Australia (EUAA) raised concerns that ElectraNet's 2008–13 regulatory control period targets were set too low.[699] ElectraNet's performance targets for the 2008–13 regulatory control period were set using the average performance over the previous five years.[700] As such, ElectraNet's performance targets were set in accordance with the STPIS. The AER considers that ElectraNet has responded to the incentives of the STPIS, and that this is reflected in improved performance during the 2008-13 regulatory control period. The AER also considers that ElectraNet's good performance during the 2008–13 regulatory control period was not as a result of performance targets being set too low. However, the AER considers that a slight increase in the targets for the 2013–18 regulatory control period balances the incentive for further improvement and the maintenance of currnet performance with the need to implement achievable performance targets.

The South Australian Council of Social Service (SACOSS) considered that recent work by the AEMC and AEMO suggested that the 'value of customer reliability' values used by ElectraNet for planning purposes were too high.[701] While the AER notes that SACOSS's concerns were primarily raised in the context of network planning, it is prudent to note that 'value of customer reliability' is not currently used to set performance targets or parameter weightings under the STPIS. As such, the AER considers that SACOSS's comments about the use of 'value of customer reliability' data has no bearing on the application of the STPIS to ElectraNet.

Market impact parameter

ElectraNet proposed a market impact parameter performance target of 1588 dispatch intervals. The AER does not accept ElectraNet's proposed performance target.

Table 11.8 shows ElectraNet's proposed historic performance count and the AER's calculated historic performance count for 2007–2011.

Table 11.8 ElectraNet's historic market impact performance data

Performance year	ElectraNet proposed performance count (dispatch intervals)	AER approved performance count (dispatch intervals)
2007	2427	2427
2008	1834	1834
2009	515	515
2010	1789	1762
2011	1375	1388
Average	1588	1585

Source: ElectraNet, *Revenue proposal, ENET 045 MITC five year submission summary*.

699 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, pp. 51–54; EUAA, *Submission to ElectraNet's revenue proposal for 2013–18*, August 2012, p. 14.
700 AER, *Draft decision, ElectraNet transmission determination 2008–09 to 2012–13*, November 2007, pp. 193–196.
701 SACOSS, *Submission to the Australian Energy Regulator consultation on ElectraNet's 2013–18 transmission network revenue proposal*, August 2012, p. 1.

As part of the annual service standards review, the AER endorsed a performance measure of 1388 dispatch intervals for ElectraNet's 2011 performance. The AER considers that this should be used to calculate ElectraNet's performance target for the 2013–18 regulatory control period. Further, the AER made several adjustments to ElectraNet's 2010 performance data for identified errors.[702] As a result, the AER has calculated a market impact parameter performance target of 1585 dispatch intervals for the 2013–18 regulatory control period.

In its submission, ECCSA raised concern with the basis for setting the market impact component's benchmark. ECCSA stated that the historic performance was based on periods where peak demand was the highest in South Australia. ECCSA stated that the AER needed to examine this aspect in considerable detail to ensure it did not result in ElectraNet getting an unearned bonus.[703] The market impact component is designed to incentivise TNSPs to conduct maintenance at times that will least affect the electricity spot price. It is a measure of network congestion that occurs as a result of transmission equipment being taken out of service, usually as a result of maintenance. Peak demand therefore has little relevance to the market impact parameter, as maintenance is generally not carried out during times of peak demand. Further, one of the objectives of the scheme is to implement a simple and transparent performance measure. The AER considers that incorporating demand would increase the complexity of the measure and reduce transparency without significant benefits. As such, the AER considers the performance target of 1585 dispatch intervals to be appropriate.

11.5 Revisions

Revision 11.1: the AER does not accept ElectraNet's proposed weightings for the 'loss of supply events > 0.05 system minutes' sub–parameter and the 'average outage duration' parameter.

Revision 11.2: the AER does not accept ElectraNet's proposed adjustments for capital work volumes.

Revision 11.3: the AER does not accept ElectraNet's proposal to exclude outages associated with contingent projects.

Revision 11.4: the AER does not accept ElectraNet's proposed performance target for the market impact component.

Table 11.1 and table 11.2 show the AER's draft decision on the service component and market impact component parameter values and weightings to apply to ElectraNet during the 2013–18 regulatory control period.

702 ElectraNet, *Email response to information request AER RP 26, 2010 MIC*, 5 September 2012.
703 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 54.

12 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) provides the transmission network service provider (TNSP) with a continuous incentive to reduce operating expenditure. When an efficiency gain is realised the cost saving is retained by the business for five years before being passed on to consumers. However, when an efficiency loss is realised the business is penalised for five years. The gains and losses realised in the current regulatory control period are used to calculate the EBSS carryover amount. The EBSS carryover amount is one of the building blocks used to calculate the TNSP's required revenue for the next regulatory control period. The EBSS also removes the incentive for a TNSP to overspend in the opex base year to receive a higher opex allowance in the following regulatory control period.

The AER is required to decide whether or not to approve ElectraNet's proposed application of the EBSS.[704] If the AER does not approve ElectraNet's application of the EBSS, it must set out details of the changes required.[705]

The application of the EBSS has two parts. Firstly, the AER must consider the carryover amounts that arise from the application of the EBSS during the 2008–2013 regulatory control period. The EBSS that applied to ElectraNet during that regulatory control period was the 'first proposed EBSS'.[706] Secondly, the AER must consider how the EBSS will apply to ElectraNet in the 2013–18 regulatory control period. The EBSS that will apply to ElectraNet for the 2013–18 regulatory control period is the 'final EBSS'.[707]

12.1 Draft decision

The AER is not satisfied ElectraNet's proposed EBSS carryover amount of –$12.2 million ($2012–13) from the application of the EBSS to the 2008–13 regulatory control period, complies with the requirements in the EBSS.[708] ElectraNet used the fouth year as the base year to forecast opex. The AER considers a carryover of –$26.9 million ($2012–13) complies with the requirements in the EBSS if the fourth year is used as the base year. However, the AER has forecast ElectraNet's efficient operating costs using the third year as a base year, in which case the EBSS total carryover amount should be –$4.5 million ($2012–13). Table 12.1 shows the carryover amounts which the AER considers comply with the requirements of the EBSS. The AER notes that the lower carryover penalty that results from chosing the third year as the base year is offset by the lower forecast opex that results from using the third year as the base year.

Table 12.1 AER draft decision on the carryover amounts arising from the application of the EBSS during 2008–13 ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
AER draft decision on carryover amounts (using 3rd year base year)	–3.8	–3.7	–1.5	0.0	4.5	–4.5

Source: AER analysis.

704 NER, clauses 6A.4.2(a)(6), 6A.14.1(iv).
705 NER, clause 6A.12.1(c).
706 AER, First proposed *Electricity transmission network service providers efficiency benefit sharing scheme*, January 2007. The AER was required to apply the First Proposed EBSS to ElectraNet for the 2008 determination. It is not to be applied in subsequent determinations; NER, clauses 11.6.17 and 11.6.18.
707 AER, *Electricity transmission network service providers efficiency benefit sharing scheme*, September 2007.
708 NER, clause 6A.14.3(d)(2).

ElectraNet's opex forecasts are not directly related to demand growth; therefore the AER considers there is no need to adjust forecast opex allowances for changes in demand over the 2013–18 regulatory control period.

The AER will exclude the cost categories listed in section 12.4.2 from forecast and actual opex for the calculation of EBSS carryover amounts. These categories will be excluded because they are not forecast using historic costs based on an efficient base year.

Table 12.2 shows the total controllable opex forecasts that the AER will use to calculate efficiency gains and losses for the 2013–18 regulatory control period.

Table 12.2 AER draft decision on ElectraNet's forecast controllable opex for EBSS purposes ($ million, 2012–13)

	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18
Total forecast opex		75.0	78.3	79.3	82.0	83.1
Adjustment for excluded cost categories		-12.6	-12.8	-13.1	-15.0	-15.3
Forecast opex adjusted for EBSS purposes	60.2	62.4	65.5	66.2	67.0	67.8

Source: AER analysis.

ElectraNet submitted its financial report with actual expenditure for 2011–12 in October 2012. However, due to time constraints the AER used ElectraNet’s estimated expenditure for the EBSS calcuations which is also consistent with ElectraNet’s revenue proposal. Actual figures for 2011–12 will be used in the final decision.

12.2 ElectraNet's proposal

ElectraNet proposed the carryover amount to be attributed to the EBSS in relation to the 2008–13 regulatory control period. It also proposed the values to be attributed to the EBSS in the 20013–18 regulatory control period.

Rewards and penalties accrued during the current regulatory control period

ElectraNet proposed that the carryover amount from the application of the EBSS during the 2008–2013 regulatory control period should be –$12.2 million.[709] The carryover amount assumes ElectraNet will realise an efficiency gain of $1.7 million in 2012–13.

ElectraNet proposed that during the 2008–13 regulatory control period, there were no material changes in demand, nor did it make any changes in capitalisation policy.

Application of EBSS in the 2013–18 regulatory control period

ElectraNet noted that the efficient operating expenditure will not be highly sensitive to changes in demand. Nevertheless, ElectraNet proposed that a demand adjustment should be applied if:[710]

709 ElectraNet, *ENET078 information pro forma part 2*, EBSS; ElectraNet, *Revenue proposal*, p. 145. The AER notes that the opex allowance and adjusted allowance were incorrectly reported in Table 11.1 of the revenue proposal. The opex allowance and adjusted allowance were correctly reported in the pro forma part 2.

710 ElectraNet, *Revenue proposal*, p. 147.

- demand growth is less than the aggregate summer connection point demand forecast in 2017–18 based on the 2012 low load forecasts provided by SA Power Networks (formerly ETSA Utilities)
- demand growth is greater than the aggregate summer connection point demand forecast in 2017–18 based on the 2012 high load forecasts provided by SA Power Networks.

ElectraNet proposed the following cost categories be excluded from the calculation of the carryover amount in the EBSS 2008–2013 regulatory control period: [711]

- debt raising costs
- network support costs
- self insurance costs.

12.3 Assessment approach

The AER is required to specify in its determination how the EBSS will be applied to ElectraNet,[712] and in doing so must have regard to the following factors listed in clause 6A.6.5(b) of the NER:

- the need to provide ElectraNet with a continuous incentive to reduce operating expenditure
- the desirability of both rewarding ElectraNet for efficiency gains, and penalising it for efficiency losses
- any incentives that ElectraNet may have to inappropriately capitalise operating expenditure, and
- the possible effects of the EBSS on incentives for the implementation of non-network alternatives.

The AER must approve the values proposed by ElectraNet to be attributed to the EBSS parameters if it is satisfied that those values comply with the requirements set out in the EBSS.[713]

The AER must approve the efficiency rewards or penalties that ElectraNet has accrued from the application of the first proposed EBSS during the 2008–2013 regulatory control period.[714] The first proposed EBSS was a transitional scheme that was subsequently updated. ElectraNet will be subject to the updated (final) EBSS[715] in the 2013–18 regulatory control period.

12.4 Reasons for draft decision

This section sets out the AER's draft decision concerning how the EBSS was applied to the 2008–2013 regulatory control period and how it will be applied to the 2013–18 regulatory control period.

12.4.1 Application of the EBSS in the 2008–13 regulatory control period

In order to apply the EBSS in the 2008–13 regulatory control period the AER needs to:

- ensure actual opex is measured using the same methodology as forecast opex

[711] ElectraNet, *Revenue proposal,* p. 146.
[712] NER, clauses 6A.4.2(6) and 6A.14.1(1)(iv).
[713] NER, clause 6A.14.3(2)(2).
[714] NER, clauses 11.6.17 and 11.6.18. The AER was required to apply first proposed guidelines to ElectraNet for the 2008 determination which do not apply to subsequent determinations.
[715] AER, *Electricity transmission network service providers efficiency benefit sharing scheme*, September 2007.

- approve the method of adjusting opex if actual demand is different to forecast demand
- verify the base year is consistent with that used for the opex forecasts
- estimate actual opex for 2012–13.

Initial adjustments to 2008–13 opex

The AER has excluded movements in provisions and land tax from both forecast and actual opex. Because these have been excluded from ElectraNet's base opex to forecast opex for the next regulatory period including these costs could reward ElectraNet for efficiency losses or penalise it for efficiency gains.[716] As the amount of movement in provisions included in the base year (2005–06) was not explicit, the AER estimated the necessary adjustment to remove movements in provisions from forecast opex.[717]

Adjustment for differences between forecast and actual demand

To calculate carryovers, the EBSS gives the AER discretion to adjust ElectraNet's forecast opex in the 2008–13 regulatory control period if actual demand growth is different to forecast demand growth.[718] ElectraNet proposed that during the 2008–13 regulatory control period there were no material changes in demand.[719] The AER disagrees and notes ElectraNet's actual demand was lower than forecast.[720] However, given that forecast opex for 2008–13 was not directly related to demand, an adjustment to opex for actual demand outcomes has not been made in this draft decision.[721]

Choice of base year

The rewards for cost efficiencies, or penalties for inefficiencies, arising from the application of the EBSS during the 2008–13 regulatory control period depend on the base year that is chosen. The AER considered two options for the base year - the fourth year (2011–12) as proposed by ElectraNet, and the third year (2010–11) which the AER considers more accurately reveals efficient costs. The issues concerning the choice of base year are fully discussed in the operating expenditure attachment in section 4.4.1.

The AER notes that ElectraNet's forecast opex in the fourth year (2011–12) exceeds the historical trend and the 2008–13 average. Figure 12.1 shows that controllable opex remains relatively stable in the first three years of the 2008–13 regulatory control period, but then clearly steps up for the final two years of the period. In comparison, most of the 2010–11 costs (by opex category and as a whole) are closer to trend and period average, suggesting 2010–11 is more representative of recurrent costs.

716 NER, clause 6A.6.5(b)(2).

717 The base year used to forecast opex for the 2008–13 regulatory contol period was 2005–06. It included an amount for overall movement in provisions which included non-regulated as well as regulated activities, opex and capex. To remove the appropriate amount from the base year the AER made assumptions about the ratio of regulated to non-regulated expenditure; the ratio of movements in provisions related to opex compared to those related to capex; and the ratio of bottom up to top down forecasts. The AER deducted the resulting estimate of movement in provisions from the forecast opex for each year of the 2008–13 regulatory contol period. It did not apply any escalators.

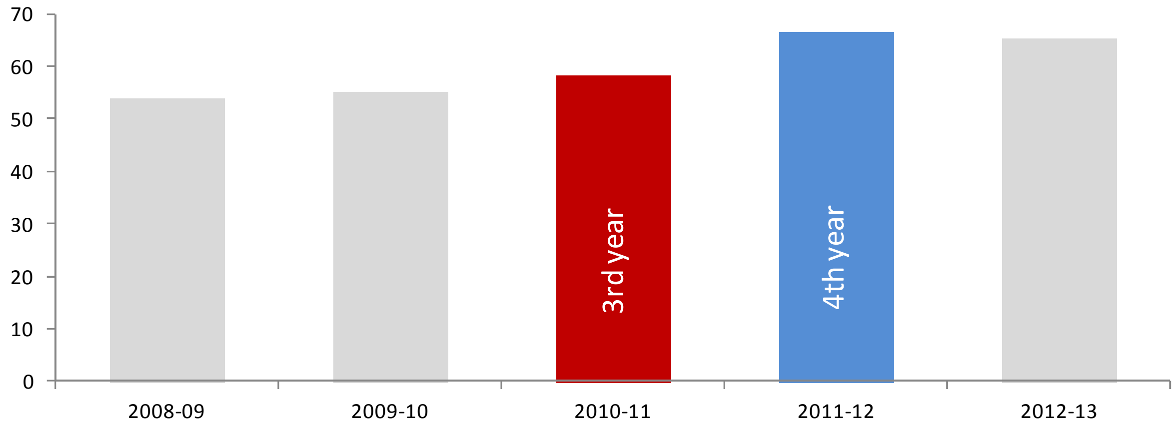
718 AER, First proposed *Electricity TNSPs efficiency benefit sharing scheme*, January 2007, p. 3.

719 ElectraNet, *Revenue proposal*, p. 145.

720 Demand attachment, section 2.4.2.

721 AER, Final decision: *ElectraNet transmission determination*, November 2007, p *x*.

Figure 12.1 Controllable opex for the 2013–18 regulatory control period ($ million, 2012–13)



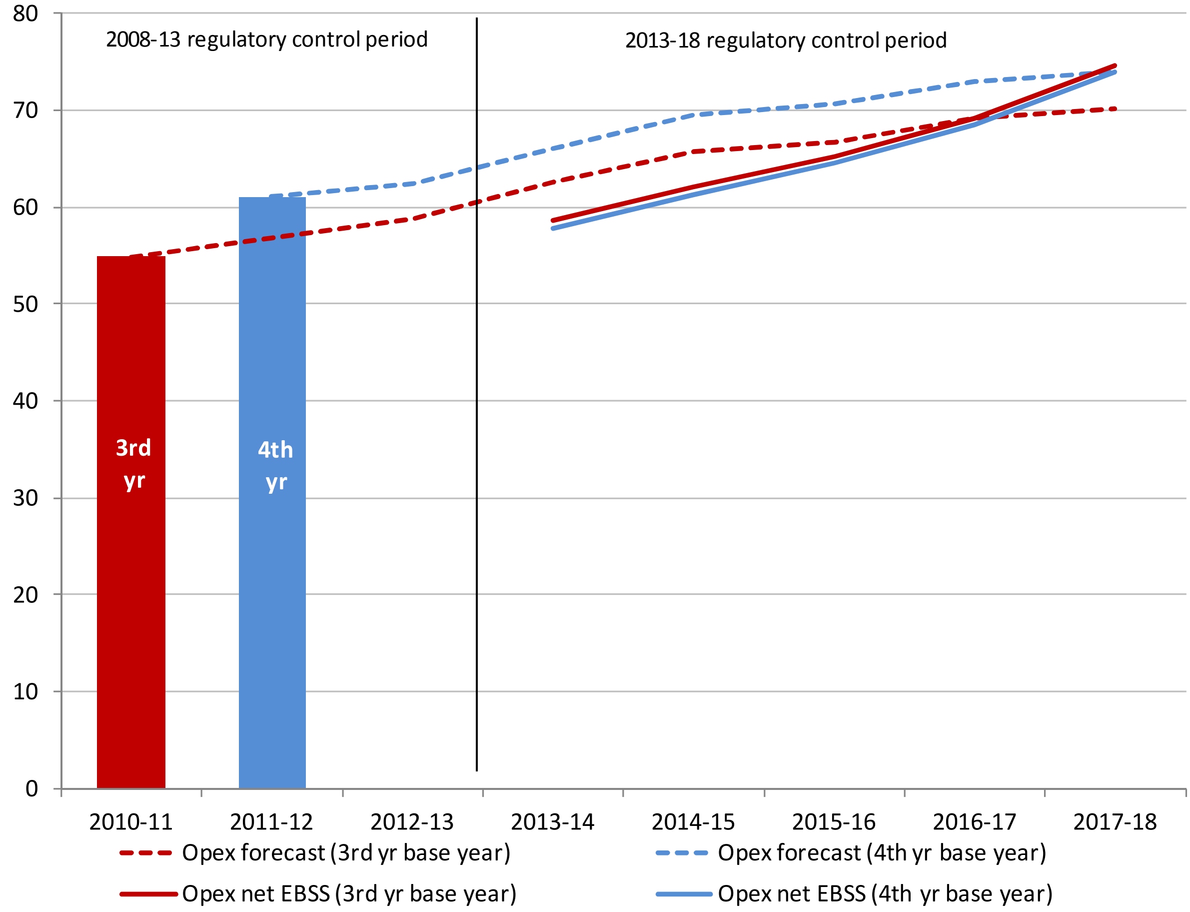
Source: ElectraNet, *Revenue proposal*.

Changing the base year from the fourth year to the third year, changes the application of the EBSS and the total carryover amount. Using the fourth year (2011–12) as a base year, ElectraNet estimated that it accrued a carryover penalty of $12.2 million when it applied the first EBSS during the 2008–13 regulatory control period. However, the method ElectraNet used to calculate the carryover does not comply with the first proposed EBSS. Using the fourth year as a base year, the AER estimates the penalty to be $26.9 million ($2012–13) (the calculation is discussed fully in the next section).

Using the third year (2010–11) as the base year (and adjusting the final regulatory year opex accordingly) the AER calculates that ElectraNet accrued a carryover of –$4.5 million.

Although the AER is reducing ElectraNet's EBSS carryover penalty, there is an offsetting impact on ElectraNet's forecast operating expenditure for the 2013–18 regulatory control period. Figure 12.2 and Table 12.3 show that forecasting ElectraNet's opex for 2013–18 using the third year results in a lower level of forecast opex (red dashed line) compared with forecasts made based on the fourth year (blue dashed line). They also show that once the EBSS carryover is taken into account there is very little net difference between the two base year scenarios (the red and blue solid line).

Figure 12.2 Comparison of EBSS adjustments to opex forecasts, using different base years ($ million, 2012–13)



AER source: AER analysis

Table 12.3 Comparison of opex forecasts, net of EBSS adjustments, using different base years ($ million, 2012–13)

	Third year base year	Fourth year base year
Total controllable forecast opex for 2013–18	334.2	353.1
EBSS total carryover	–4.5	–26.9
Total controllable Opex for 2013–18 net of EBSS carryover	329.7	326.2

Source: AER analysis.

Adjustment to 2012–13 actual opex

The following section explains that ElectraNet's proposed EBSS carryover amount of –$12.2 million from the application of the EBSS to the 2008–13 regulatory control period does not comply with the requirements in the first proposed EBSS because of the assumptions it made about its fifth year opex. ElectraNet estimated that its fifth year opex would be $66.3 million. The AER considers a final year adjusted opex of $62.2 million,[722] and consequent total carryover of –$4.5 million for the 2013–18 regulatory control period, is consistent with the relevant requirements of the EBSS.

The carryover amount for the fifth year and therefore the total EBSS carryover, changes depending on what 'actual' opex is estimated for the fifth year. An estimate is used because a TNSP submits its revenue proposal before the fifth year commences. ElectraNet estimated that its 2012–13 opex would be $66.3 million. The AER does not accept ElectraNet's estimated opex for the fifth year because it assumes ElectraNet will achieve an opex efficiency gain of $1.7 million in that year.

The first proposed EBSS says the AER, rather than the TNSP, will estimate the actual opex for the fifth year.[723] The estimate of final year opex needs to be adjusted to ensure ElectraNet retains the efficiency gains (losses) made in each year for only five years.[724] ElectraNet assumed it would achieve an efficiency gain of $1.7 million in 2012–13 which would be included in the EBSS carryover amounts for five years and thus increase the total carryover amount by $8.5 million. Conversely, ElectraNet's forecast opex should be required to reflect the same efficiency gain. However, the majority of ElectraNet's opex are forecast on a bottom up build and are independent of historic costs (and efficiency gains). As a result, it would receive the reward without making the commensurate reduction its forecast opex for the 2013–18 regulatory control period.

The first proposed EBSS does not provide a formula to estimate the actual opex in the fifth year. Therefore the AER used the formula from the distribution network service providers EBSS to estimate the actual expenditure for 2012–13:[725]

$$A_5^* = F_5 - (F_f - A_f)$$

where:

A_5^* is the estimate actual opex required to calculate the efficiency gain or loss for the final year

F_f and A_f are the forecast and actual opex figures respectively in the base year (year 3).

Applying the formula and using the fourth year as a base year, results in a final year adjusted opex of $66.6 million and a carryover penalty of $ 26.9 million (compared with ElectraNet's proposed $12.2 million).

When the AER applies the EBSS formula (using the third year as the base year) it calculates a final year estimated opex of $62.2 million and a total carryover of –$4.5 million for the 2013–18 regulatory control period. Table 12.4 sets out the carryover amounts accrued in the 2013–18 regulatory control period.

Figure 12.3 shows how these were calculated applying the EBSS in the 2008–13 regulatory control period.

722 Adjusted opex is controllable opex less land tax and movements in provisions (which are excluded from the EBSS).

723 AER, First proposed *Electricity TNSPs efficiency benefit sharing scheme*, January 2007, p. 2.

724 To ensure efficiency gains made are only retained for five years, the efficiency gain assumed for 2012–13 should be equal to the inverse of the gain (loss) made in 2011 12 (that is, the average efficiency gain over the two years should be assumed to be zero). Applying the formula, ElectraNet's estimated efficiency loss of $4.1 million in 2011–12 must be offset by an efficiency gain of $4.1 million in 2012–13.

725 AER, *Electricity distribution network service providers efficiency benefit sharing scheme*, June 2008, p. 6. The relevant formula in the final TNSP EBSS assumes a fourth year base year. The formula in the DNSP EBSS allows a third year base year. Otherwise both formulas are the same.

Table 12.4 EBSS carryover amount accrued in the 2013–18 regulatory control period ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
▪ ElectraNet proposed	–2.7	–4.6	–4.2	–2.4	1.7	–12.2
▪ AER draft decision	-3.8	–3.7	–1.5	0.0	4.5	–4.5

Source: ElectraNet, *Revenue proposal*; AER analysis.

Figure 12.3 Application of EBSS in 2008–13 using third year base year ($ million, 2012–13)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Opex allowance	63.6	65.6	67.9	71.1	73.8					
Adjusted allowance	50.9	52.5	54.4	56.9	58.3					
Actual opex	60.9	63.1	68.7	73.1	n.a.*					
Adjusted actual	51.0	54.8	58.2	75.3	62.2					
Efficiency gain	-0.1	-2.2	-1.5	-4.5	4.5					

Carryover	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	
Year -4		-0.1	-0.1	-0.1	-0.1	-0.1					
Year -3			-2.2	-2.2	-2.2	-2.2	-2.2				
Year -2				-1.5	-1.5	-1.5	-1.5	-1.5			
Year -1					-4.5	-4.5	-4.5	-4.5	-4.5		
Year 0						4.5	4.5	4.5	4.5	4.5	
Total Carryover						**-3.8**	**-3.7**	**-1.5**	**0.0**	**4.5**	**-4.5**

Source: ElectraNet, *Revenue proposal*; ElectraNet, *ENET145 Information pro forma*; ElectraNet, *ENET239 Provisions and accrued liabilities,* 21 August 2012.

Note: The AER has determined the adjusted actual opex for 2012–13 according to the formula $A_5^* = F_5 - (F_f - A_f)$. Actual opex is not used.

12.4.2 Application of EBSS in the 2013–18 regulatory control period

The AER must approve the values that are to be attributed to the EBSS for the 2013–18 regulatory control period in its determination if it is satisfied they comply with the final EBSS.

Demand growth adjustment

To calculate carryover amounts, the EBSS requires that ElectraNet's forecast opex is adjusted if forecast demand is different to actual demand over the regulatory control period. This is to provide that ElectraNet is not rewarded (or penalised) for cost decreases (increases) due to demand growth factors beyond its control. The EBSS specifies that the adjustments must be made using the same relationship between growth and expenditure used in establishing forecast opex. However, adjustments must only be applied to those components of the opex that have a direct relationship to demand growth.[726]

[726] AER, *Electricity TNSPs efficiency benefit sharing scheme*, September 2007, section 2.4.2, p. 7.

The AER considers there is no need to adjust ElectraNet's forecast opex if actual demand is different to forecast demand. This is because ElectraNet's forecast opex does not have a direct relationship to demand growth. The reason for this is that ElectraNet's opex forecasting model does not use demand growth as a direct input. While the opex model has network growth escalators these relate to asset growth and their sensitivity to demand is unclear. ElectraNet itself noted that it expected that the efficient opex level will not be highly sensitive to changes in demand in the forthcoming period.[727]

While ElectraNet noted that opex is not highly sensitive to changes in demand it considered the EBSS required it to propose a demand adjustment. ElectraNet proposed that an adjustment should be applied if demand growth were outside of SP Power Network's (formerly ETSA Utilities) low load and high load aggregate summer connection point demand forecast in 2017–18.[728] These triggers are consistent with ElectraNet's proposal that its overall demand forecasts be based on SP Power Network's medium load forecasts. However, the AER considers SP Power Network's forecasts are not a realistic expectation of demand (discussed in attachment 2). It therefore does not accept adjustment triggers based on them. Finally, ElectraNet did not propose a method by which forecast opex could be adjusted if actual demand was different to forecast demand.

Excluded cost categories

The EBSS allows TNSPs to propose uncontrollable cost categories to be excluded from its operation. A TNSP is thus not rewarded (or penalised) for cost decreases (increases) over which it has limited control. The AER excludes costs from the EBSS calculations if:

1. they are uncontrollable costs
2. they are not forecast using historic expenditure in an efficient base year. These costs are excluded because the EBSS assumes costs are forecast using a base-step-trend methodology.

The AER will exclude the following cost categories from forecast and actual operating expenditure for the 2013–18 regulatory control period for the purpose calculating EBSS carryovers:

- debt raising costs
- network support costs
- self insurance costs
- movements in provisions
- land tax
- additional regulatory reset costs.

The AER will exclude these cost categories because they are not forecast using historic expenditure in an efficient base year, rather they are added as bottom up forecasts. These costs will be excluded in addition to the adjustments set out in section 2.4.2 of the EBSS, which exclude the cost of recognised pass through events.

The EBSS requires that the AER must measure actual opex over the regulatory control period using the same cost categories and methodology as those the AER uses to calculate the forecast opex for

[727] ElectraNet, *Revenue proposal*, p. 147.
[728] ElectraNet, *Revenue proposal*, p. 147.

that regulatory control period.[729] To determine ElectraNet's forecast opex the AER has removed the movement in provisions, land tax and additional regulatory costs from ElectraNet's base year controllable opex.[730] Therefore, the AER will exclude any movements in provisions, land tax and additional revenue costs from ElectraNet's actual opex during the forthcoming regulatory control period.

12.5 Revisions

Revision 12.1: Table 12.2 outlines the EBSS increments and decrements included as building blocks in the determination of ElectraNet's annual revenue requirement.

Revision 12.2: the AER will use the opex forecasts in Table 12.2 to calculate EBSS carryovers.

Revision 12.3: the AER does not accept ElectraNet's proposed demand adjustment triggers. As ElectraNet's operating expenditure is not directly related to demand growth, adjustments to forecast operating expenditure allowances for the purpose of calculating carryover amounts will not be applied.

Revision 12.4: the AER will exclude the following cost categories from forecast and actual operating expenditure for 2013–18 for the purpose calculating EBSS carryovers:

- debt raising costs
- network support costs
- self insurance costs
- movements in provisions
- land tax
- additional regulatory reset costs.

729 AER, *Electricity transmission network service providers efficiency benefit sharing scheme,* September 2007, p. 7.
730 ElectraNet, ENET239, response to information request AER RP 011.

13 Contingent projects

For the 2013–18 regulatory control period, ElectraNet proposed expenditure on 21 contingent projects with a combined value of $2547 million ($2012–13). Generally, contingent projects are network augmentation projects that are significant, reasonably required, but are not yet committed and are not provided for in the capex forecast. Such projects are linked to unique investment drivers (rather than general investment drivers such as expectations of load growth in a region) and are triggered by a defined 'trigger event'. The occurrence of the trigger event must be probable during the relevant regulatory control period.[731]

If the trigger event occurs during the 2013–18 regulatory control period, then the AER will separately assess the contingent project under clause 6A.8.2 of the National Electricity Rules (NER) on application by ElectraNet (contingent project application). The trigger event must be described in such terms that the occurrence of that event or condition is all that is required for the revenue determination to be amended.[732] For this reason, the trigger event must be adequately defined and the proposed contingent capex must reasonably reflect the capex criteria under the NER.[733]

13.1 Draft decision

The AER does not accept any of the contingent projects as proposed by ElectraNet, because they do not meet the NER requirements, as discussed below.[734]

The AER does not accept the group of projects that address circumstances that have already been taken into account in the development of the ex ante capex allowance, as follows:

- Two proposed contingent projects are triggered by a demand increase which is within ElectraNet's demand forecast for the 2013–18 regulatory control period.
- Four proposed contingent projects are triggered by a connection point request but are within ElectraNet's demand forecast for the 2013–18 regulatory control period.

The AER does not accept the group of projects which are not considered probable during the 2013–18 regulatory control period, as follows:

- four proposed contingent projects have a demand increase above ElectraNet's demand forecast as the trigger event. ElectraNet did not specifically identify the underlying driver that will cause the step increase in demand. These projects therefore do not appear to be reasonably required to achieve the capex objectives[735] and the trigger event cannot be said to be probable during the 2013–18 regulatory control period.[736]
- two proposed contingent projects are above the demand forecast and were attributable to the proposed expansion of BHP Billiton's Olympic Dam mine.
- three proposed contingent projects are driven by market benefits and ElectraNet has not identified the underlying driver of the projects.

731 NER, clause 6A.8.1(c)(5).
732 NER, clauses 6A.8.1(c)(4); 6A.8.2.
733 NER, clause 6A.8.1(b)(2)(ii).
734 NER, clause 6A.8.1.
735 NER, clause 6A.8.1(b)(1).
736 NER, clause 6A.8.1(c)(5).

- one proposed contingent project, Eyre Peninsula Connection Point, is not technically feasible as presented.

The AER considers that five of ElectraNet's proposed contingent projects could meet the NER requirements. However, the AER does not accept these five projects as contingent projects because it does not consider that the trigger events defined by ElectraNet are appropriate. The trigger events proposed by ElectraNet have not been adequately defined.[737] Before the AER can accept these proposed contingent projects, it requires ElectraNet to revise its project trigger definitions. This group of projects and indicative costs ($2012–13) are set out below (indicative trigger events for these projects are set out at attachment C). The AER will re-assess these projects and their trgger events in making its final decision:

- Davenport Reactive Support ($42 million)
- Mid North Connection Point ($59 million)
- Upper North Region Line Reinforcement ($62 million)
- Riverland Reinforcement ($407 million)
- South East to Heywood Interconnection upgrade ($96 million).

Appendix C sets out all of ElectraNet's proposed contingent projects. It also includes the AER's indicative project trigger event definition for the projects accepted in principle.

Section 13.4 includes discussion of specific issues that relate to ElectraNet's proposed contingent projects.

13.2 Assessment approach

The AER reviewed each of ElectraNet's proposed contingent projects in the context of the NER requirements.[738] It considered whether:

- the proposed contingent project is reasonably required to achieve any of the capex objectives[739]
- the proposed contingent project expenditure is not otherwise provided for in the capex proposal.[740] A TNSP must include forecast capex in its revenue proposal to meet expected demand.[741]
- the proposed contingent project reasonably reflects the capex criteria,[742] and exceeds the defined threshold[743]
- the trigger events are appropriate. This included assessing whether the trigger event is reasonably specific,[744] makes the project reasonably necessary to achieve the capex objectives,[745] and is all that is required for the revenue determination to be amended.[746] The occurrence of the trigger event must be probable during the 2013–18 regulatory control period.[747]

737 NER, clause 6A.8.1(c).
738 NER, clause 6A.8.1.
739 NER, clause 6A.8.1(b)(1).
740 NER, clause 6A.8.1(b)(2)(i).
741 NER, clause 6A.6.7(a)(1).
742 NER, clause 6A.8.1(b)(2)(ii).
743 NER, clause 6A.8.1(b)(2)(iii).
744 NER, clause 6A.8.1(c)(1).
745 NER, clause 6A.8.1(c)(2).

The AER has also considered the interaction between the ex ante capex allowance and projects included as contingent projects. A TNSP may recover revenue to meet expenditure on capex projects in two ways.

First, a TNSP is provided with an ex ante allowance to undertake a range of projects that are likely to be needed within the regulatory control period. This ex ante allowance is based on an assessment of the total capex likely to be required to achieve the capex objectives. Determining the likelihood of occurrence includes considering foreseeable increases in demand across the network. Ultimately the ex ante allowance is determined by balancing the probablility of a range of projects. In total the ex ante allowance is expected to meet the needs of the TNSP during the regulatory control period.

The TNSP is expected to manage its business within this allowance. The AER accepts that not all possible projects identified by the TNSP as part of its revenue proposal may be undertaken. Similarly, some projects may be undertaken that were not identified during the revenue determination. The projects ultimately undertaken will be determined through the TNSP's asset management framework in response to circumstances as they develop. This approach provides an incentive for the TNSP to manage its affairs as efficiently as possible since it can keep the benefit of any capital allowance that is not ultimately spent.

Second, a TNSP may nominate specific projects as contingent projects. When a contingent project is triggered, the revenue determination is amended and additional revenue is allowed in the regulatory control period. Generally, contingent projects are large projects which are less certain than the range of projects considered when determining the ex ante allowance. They are also linked to specific triggers. For example, a major new load such as a mine may be under consideration by a potential customer. It is uncertain whether the project will go ahead, but if it does, it will require substantial augmentation of the system. Such a project is a good candidate for nomination as a contingent project. Despite this uncertainty, if it was included in the ex ante allowance there is a high likelihood that either customers or the TNSP would be disadvantaged. Treating less certain, but high revenue impact projects as contingent projects means that customers are not required to pay unless the project goes ahead. The interests of the TNSP are also protected.

The determination of the two types of capex allowance requires the exercise of judgement. Various types of projects and circumstances must be considered when determining each allowance. Also some potential projects will be excluded from consideration altogether because the occurrence of the trigger event cannot be said to be probable during the relevant regulatory control period.

Potential projects that have been considered when determining the ex ante allowance cannot also be considered as contingent projects. Similarly, if the nominated contingent projects cover a particular set of circumstances, then those projects should be excluded from consideration of the ex ante allowance.

The AER had regard to:

- ElectraNet's revenue proposal, including attachments[748]
- submissions[749]

[746] NER, clauses 6A.8.1(c)(4); 6A.8.2.
[747] NER, clause 6A.8.1(c)(5).
[748] ElectraNet revenue proposal.
[749] The AER received a submission on contingent projects from the South Australian Council of Social Service and from the Energy Consumers' Coalition of South Australia.

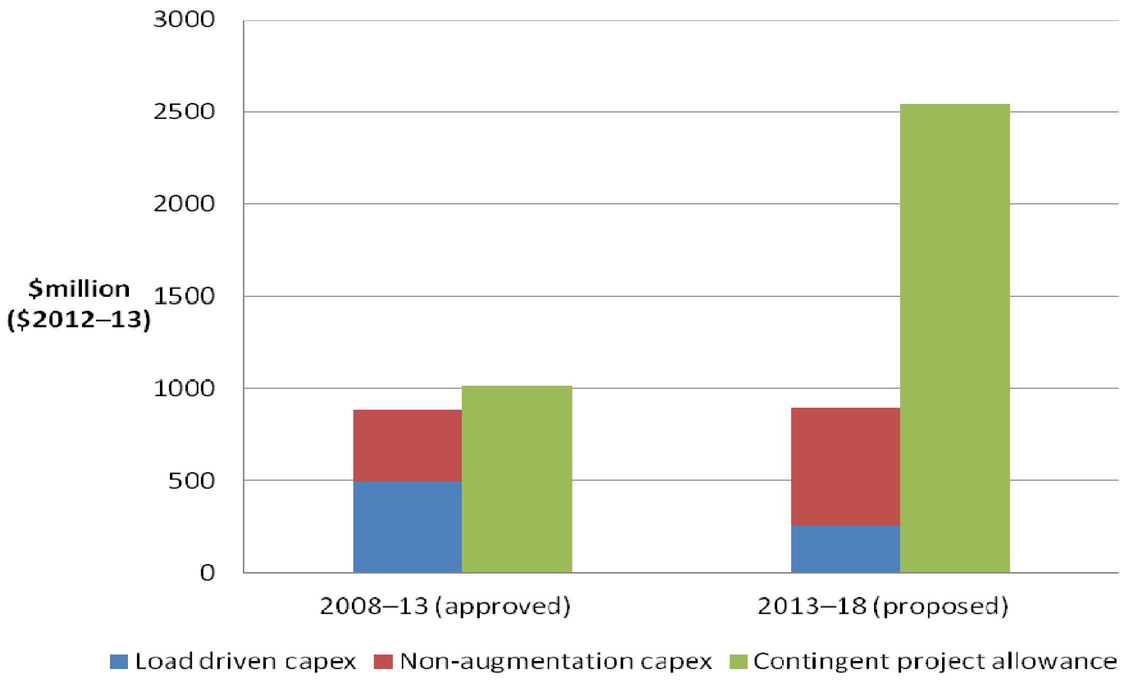
- Australian Energy Market Operator (AEMO) report[750]
- EMCa's technical review of ElectraNet's proposal.[751]

13.3 ElectraNet's proposal

In addition to its forecast capex, ElectraNet proposed 21 contingent projects with a combined value of approximately $2547 million ($2012–13). The proposed contingent project expenditure is a 150 per cent increase on what the AER provided ($894 million) in its final decision for the 2008–13 regulatory control period[752] and a significant increase on that proposed in ElectraNet's 2008–13 revenue proposal ($947 million, nominal).[753]

ElectraNet stated the proposed contingent projects are in addition to ElectraNet's objective of keeping customer price impacts in line with movements in the consumer price index (CPI).[754] ElectraNet noted this objective in recognition of community concern over the cost of electricity.[755] In keeping with this objective, Figure 13.1 shows ElectraNet's proposed capex forecast for the 2013–18 regulatory control period is similar to the actual and estimated capex it incurred over the 2008–13 regulatory control period.

Figure 13.1 Proposed load driven capex and contingent projects ($ million, 2012–13)



Source: AER, *Final decision ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, p. 61; ElectraNet, *Revenue proposal*, pp. 77–78; AER analysis.

ElectraNet's forecast capex for the 2013–18 regulatory control period is similar to the actual capex incurred during the 2008–13 regulatory control period.[756] The proposed load driven capex is

[750] AEMO, 2012 ElectraNet Revenue Cap Review: Capital Projects Assessment Report, 4 June 2012, available at http://www.aemo.com.au/Electricity/Planning/Reports/South-Australian-Advisory-Functions/ElectraNet-Revenue-Cap-Review
[751] EMCa, *ElectraNet technical review*, October 2012.
[752] Figure 13.1 escalates these nominal values to $2012–13.
[753] ElectraNet, *Revenue proposal*, pp. 69–70.
[754] ElectraNet, *Revenue proposal*, p. 1.
[755] ElectraNet, *Revenue proposal*, p. 1.
[756] ElectraNet, *Revenue proposal*, pp. 77–78.

considerably lower than its allowance in the AER's 2008 decision but an increase in replacement and refurbishment capex, and strategic land and easement capex, offsets this difference.

13.3.1 AEMO review

ElectraNet submitted 29 contingent projects for AEMO to review.[757] AEMO discussed with ElectraNet the formulation of trigger events to ensure they were as clear and specific as possible.

AEMO found that the proposed contingent projects were:

- able to cover the range of probable future development scenarios
- required under the specific development scenarios (demand growth, generation growth and identified market benefits).[758]

It thus generally supported ElectraNet's contingent project proposal because it considered that listing contingent projects is a prudent mechanism for managing uncertainty, particularly where it may result in high-cost augmentations.[759] Further, based on the project descriptions, AEMO considered that the 29 contingent projects would be able to cover the range of probable future development scenarios.[760]

AEMO's review of ElectraNet's contingent projects was limited to considering whether ElectraNet has sufficient contingent projects to respond to changing conditions.[761] The AER accepts AEMO's findings that these projects are able to cover the range of probable future development scenarios and are likely required under the specific development scenarios.[762]

The AER is required to review ElectraNet's contingent projects in accordance with the specific requirements set out in the NER. The AER's approach and views on the proposed contingent projects are therefore likely to differ from AEMO's because the NER requires the AER to consider these projects in the context of Chapter 6A.

13.4 Reasons for draft decision

The AER's general findings on ElectraNet's proposed contingent projects are as set out below. The AER does not accept any of the projects proposed by ElectraNet as contingent projects. There are three key problems with the projects as proposed.

The first group of projects are those that address circumstances that have already been taken into account in the development of the ex ante capex allowance. Specifically, there are six projects that address demand scenarios already included in the ex ante allowance. The demand scenarios are adequately covered in the ex ante allowance and to include them as contingent projects would be to allow double recovery for the same demand.

The second group of projects are not considered probable during the 2013–18 regulatory control period. Hence they should not be included in either the ex ante allowance or as contingent projects. This group includes:

757 ElectraNet did not include all 29 contingent projects that it submitted to AEMO in its Revenue proposal.
758 AEMO, *2012 ElectraNet Revenue Cap Review: Capital Projects Assessment Report*, 4 June 2012, p. 17.
759 AEMO, *2012 ElectraNet Revenue Cap Review: Capital Projects Assessment Report*, 4 June 2012, p. v.
760 AEMO, *2012 ElectraNet Revenue Cap Review: Capital Projects Assessment Report*, 4 June 2012, p. 20.
761 AEMO, *2012 ElectraNet Revenue Cap Review: Capital Projects Assessment Report*, 4 June 2012, p. 17.
762 AEMO, *2012 ElectraNet Revenue Cap Review: Capital Projects Assessment Report*, 4 June 2012, p. 17.

- six projects for which ElectraNet did not appropriately identify the underlying trigger events for contingent projects. ElectraNet expressed the trigger events in general terms, for example, a demand increase at a particular location. The demand increase is above the demand forecast (both ElectraNet and the AER's demand forecast) so it cannot be said to be probable during the regulatory control period. The AER expects ElectraNet to identify the underlying driver of a project which makes the project reasonably necessary to achieve the capex objectives.[763] This trigger eventshould be all that is required for the revenue determination to be amended under clause 6A.8.2.[764]
- three projects which were based on speculation about an event occurring, such as generation coming on line, which might drive a project. While ElectraNet identified a driver of these projects, the NER requires that the trigger event is probable.[765]
- one of the proposed contingent projects, Eyre Peninsula Connection Point, is not technically feasible as presented.

The third group of projects are those that are not adequately defined. These projects are uncertain, but ElectraNet has not explained why it considers these projects are reasonably required, with specific reference to the underlying driver of the project. Potentially, these projects may be acceptable if they are clearly defined and/or the trigger events are clarified and linked to specific drivers. There are five projects in this class of projects with a potential value of $666 million. The AER therefore proposes alternative indicative trigger events for these projects.These projects will be re-assessed by the AER when making its final decision.

These issues are discussed below.

13.4.1 Contingent projects associated with load growth

ElectraNet considered its proposed ex ante capex allowance is sufficient to meet its high, medium and low demand scenarios:

> The large majority of network projects included in the capex forecast are required to be completed within the forthcoming regulatory period irrespective of whether demand growth follows the high, medium or low demand forecast and irrespective of where new generation sources locate to meet the growth in demand. This demonstrates the robustness of the forecasts to a range of reasonable scenarios. [766]

ElectraNet used Roam Consulting's scenario analysis to test the robustness of its capex forecast.[767] The Roam Consulting analysis shows that ElectraNet's capex forecast would be sufficient to meet the capex driven by its medium demand forecast.[768] Roam assessed whether ElectraNet's capex forecast was sufficient to meet the range of demand uncertainties, that is, whether it was sufficient to meet the high, medium and low demand scenarios.[769]

The AER's consultant, EMCa, reviewed ElectraNet's proposal and the advice from Roam Consulting. EMCa found that Roam Consulting's analysis of ElectraNet's 'medium' demand capex was very close to the weighted average capex that EMCa derived. EMCa therefore concluded that ElectraNet's capex forecast is consistent with the NER as it meets a reasonable expectation of the range of

763 NER, clauses 6A.8.1(c)(2),(3).
764 NER, clause 6A.8.1(c)(4).
765 NER, clause 6A.8.1(c)(5).
766 ElectraNet, *Revenue proposal*, p. 76.
767 ElectraNet, *Revenue proposal*, p. 65.
768 EMCa, *ElectraNet technical review*, October 2012, pp. 89–90.
769 EMCa, *ElectraNet technical review*, October 2012, p. 147.

demand forecasts. EMCa refers to this range of demand forecasts as a 'demand envelope'.[770] In other words, ElectraNet's capex forecast was sufficient to cover natural incremental demand growth provided by the high, medium and low demand scenario envelope.[771]

Therefore, no contingent projects are needed to address the high, medium or low demand scenarios as these are already taken into account in determining the ex ante allowance. To allow for these projects as contingent projects would potentially lead to customers compensating ElectraNet twice for the same set of circumstances via contingent project allowances. The ex ante allowance balances the probablility of a range of projects and is therefore, expected to meet the needs of the TNSP during the regulatory control period.

The use of the term 'expected demand' in the capex objectives implies inherent uncertainty around demand.[772] Under a probabilistic approach to forecasting capex, the ex ante capex allowance does not include the entire revenue for every project which a TNSP considers is likely to occur. Rather, if projects are included in the ex ante capex allowance, then the allowance includes a proportion of the capex attributable to each project based on the probability of the project occurring during the regulatory control period. At the time of the AER's determination some projects will be considered more likely than others. However, in some areas of the network, actual demand growth will be slower than forecast and TNSPs will be able to defer expenditure. In other areas of the network, demand will grow more quickly than forecast and TNSPs may be required to incur additional capex.

EMCa considered:

> ...the TNSP must propose forecast capex that is a probabilistic expectation of its requirements. This is a balanced concept in that a lower-than-expected demand does not give rise to a 'claw-back' from consumers if less capex is subsequently required; equally a higher-than-expected demand needs to be met by the TNSP without additional compensation during the RCP in question.[773]
>
> ...there is a more-or-less equal chance that a greater or lesser capex is required, depending on demand and other uncertainties... [774]

The AER considered that ElectraNet's forecast capex would allow it to meet ElectraNet's high, medium and low demand scenarios. The AER determined that several of ElectraNet's proposed contingent projects sat in a band between ElectraNet's medium and high demand scenarios. The AER therefore, considered that ElectraNet's forecast capex would be sufficient to meet these contingent projects that were triggered by demand increases between ElectraNet's medium and high demand scenarios.

However, the AER has substituted a lower overall demand forecast and has reduced ElectraNet's load driven capex accordingly (see attachments 2 and 4). The AER considers the determined capex allowance is sufficient to accommodate the range of demand scenarios around the AER's demand forecast.[775]

The AER's band of medium to high demand scenarios is below ElectraNet's band of medium to high demand scenarios. The AER therefore considers that some of ElectraNet's proposed contingent projects might now be relevant if a lower demand forecast is applied in the final decision. In particular, those projects that were in the band between ElectraNet's medium and high demand scenarios may

770 EMCa, *ElectraNet technical review*, October 2012, p. 89. EMCa noted that ElectraNet had tested demand sensitivity using a relatively narrow range of approximately + 4% – -3%.
771 EMCa, *ElectraNet technical review*, para 243.
772 NER, clause 6A.6.7(a)(1).
773 EMCa, *ElectraNet technical review*, pp. 88–89.
774 EMCa, *ElectraNet technical review*, October 2012, p. 147.
775 The AER notes that it has not done an analysis of the sensitivity of the forecast capex to the high, medium and low demand scenarios.

need to be reconsidered. To cover such projects, it might therefore be necessary for ElectraNet to propose some additional contingent projects in its revised revenue proposal. However, ElectraNet would need to justify adding any contingent projects.

If ElectraNet, in its revised proposal, proposes contingent projects associated with load growth, the AER expects ElectraNet to demonstrate clearly that the contingent project expenditure is not otherwise provided for in the ex ante capex allowance. ElectraNet is also required to identify clearly the underlying driver of the contingent project.

The AER considers that ElectraNet should provide an ex ante capex forecast with clearly identified scenarios and probabilities to allow the AER to properly consider the boundary between the ex ante allowance and contingent projects.

There are six proposed contingent projects in this category that the AER has not accepted. The six projects can be further grouped under two sub-categories:

- General load growth
- Connection point request but within forecast demand.

Projects associated with general load growth

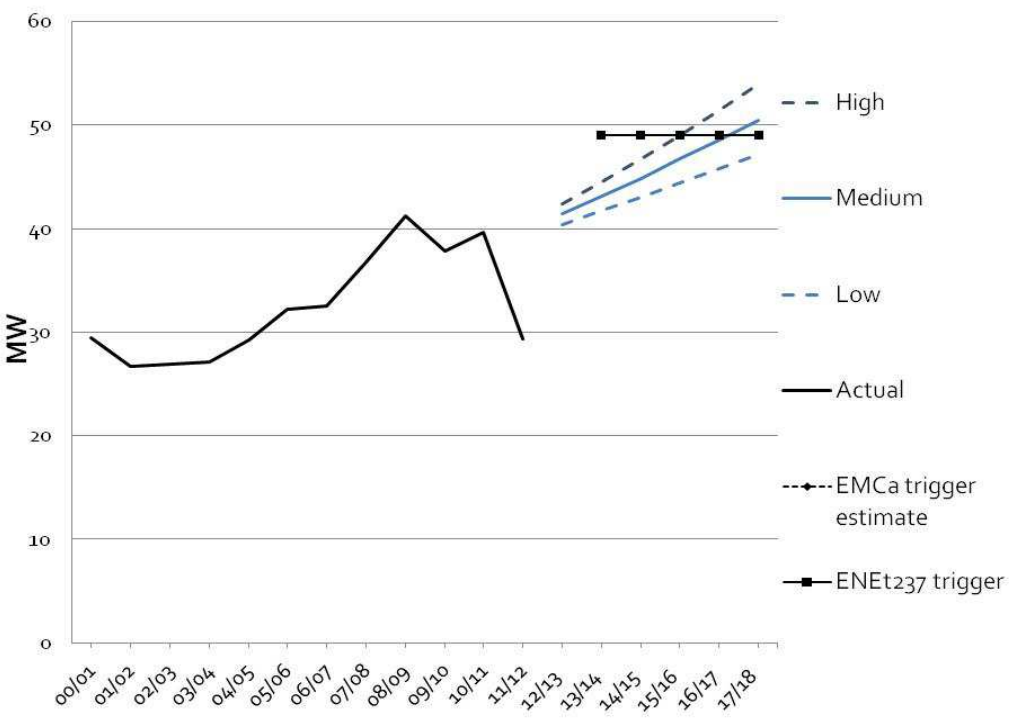
ElectraNet included two proposed contingent projects in its revenue proposal which are triggered by a demand increase that ElectraNet forecast will occur in the 2013–18 regulatory control period:

- Lower Eyre Peninsula Reinforcement
- Yorke Peninsula Reinforcement.

The AER does not accept these projects because ElectraNet's forecast capex already provides for these projects. As an example, Figure 13.2 sets out the historical and forecast demand compared to the demand increase that would trigger the Lower Eyre Peninsula Reinforcement project. The demand increase, proposed by ElectraNet as the trigger event for this project, is forecast to occur during the 2013–18 regulatory control period.[776]

[776] EMCa, *ElectraNet technical review*, October 2012, p. 149.

Figure 13.2 Lower Eyre Peninsula reinforcement



Source: EMCa, *ElectraNet technical review*, October 2012, p. 150.

Projects triggered by a connection point request but within demand forecast

ElectraNet included four proposed contingent projects which are triggered by a DNSP request for a new connection point:

- Fleurieu Peninsula Reinforcement
- Western Suburbs Reinforcement
- Northern Suburbs Reinforcement
- Port Pirie System Reinforcement.

New connections are generally driven by demand. Accordingly, a TNSP should forecast new connections based on its demand forecast. These four proposed contingent projects are for new connection points which appear to be driven by demand increases that are within ElectraNet's demand forecast for the 2013–18 regulatory control period. In other words, the demand increase that is the trigger for these four proposed contingent projects is already forecast to occur in the 2013–18 regulatory control period and is therefore already covered by the ex ante forecast capex.[777] The AER therefore does not accept these four proposed contingent projects.

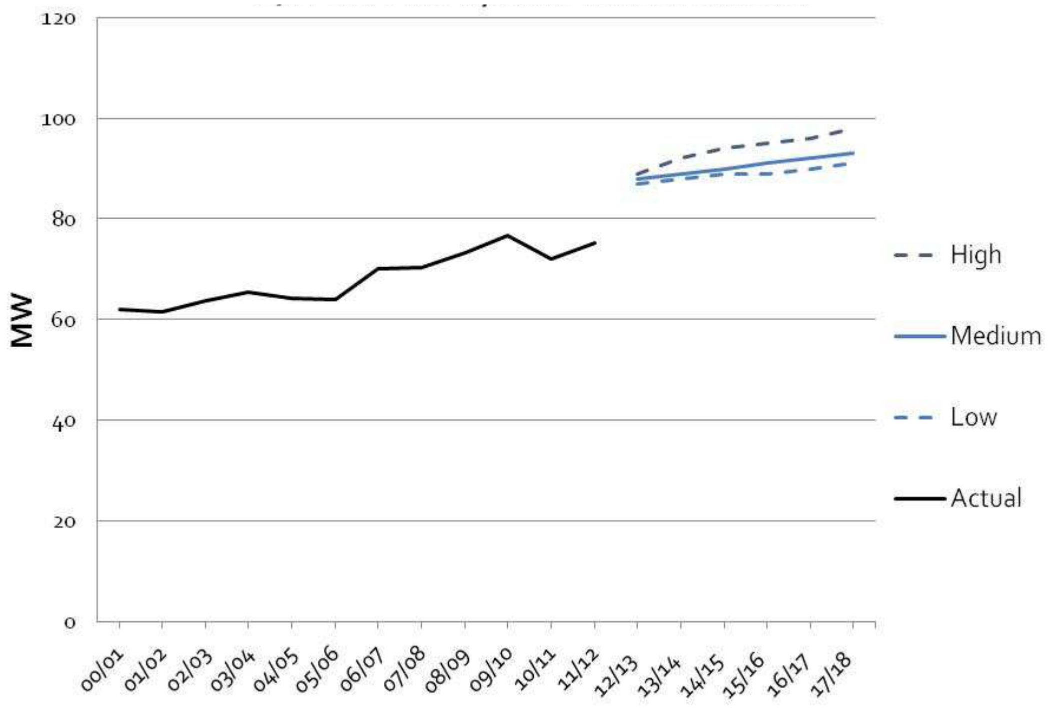
Figure 13.3 sets out the historic and forecast demand for the Port Pirie system reinforcement project.[778] The request for a connection point is driven by a demand increase which is forecast to

[777] EMCa, *ElectraNet technical review*, October 2012, p. 150.

[778] ElectraNet, *Email response to information request AER RP 038, contingent project triggers*, ENET 282, 26 October 2012, p. 10 [public version]: ElectraNet subsequently provided an alternative trigger for the Port Pirie system reinforcement. The AER was not able to consider this as part of its draft decision but will consider alternative trigger events that are proposed in the revised revenue proposal.

occur during the 2013–18 regulatory control period. EMCa stated that these projects were '... essentially a trend growth forecast and no evidence of a step demand increase was provided to us'.[779]

Figure 13.3 Port Pirie system reinforcement



Source: EMCa, *ElectraNet technical review*, October 2012, p. 151.

13.4.2 Projects which are not probable during the regulatory control period

Projects that require a step change in demand—before they are triggered—may be included as contingent projects. The AER would, however, expect ElectraNet to justify the inclusion of the contingent project by identifying the driver of the project that will make the occurrence of the trigger event probable during the 2013–18 regulatory control period. Without a specific driver or explanation of why demand will increase more than the demand forecast the AER cannot determine that the occurrence of the trigger event is probable during the 2013–18 regulatory control period.

The AER therefore does not accept:

- projects if the required demand increase to trigger the project is not justified
- projects driven by the expansion of Olympic Dam
- market benefits projects with no specific trigger
- projects that do not appear to be feasible.

These categories of projects are discussed below.

[779] EMCa, *ElectraNet technical review*, October 2012, p. 150.

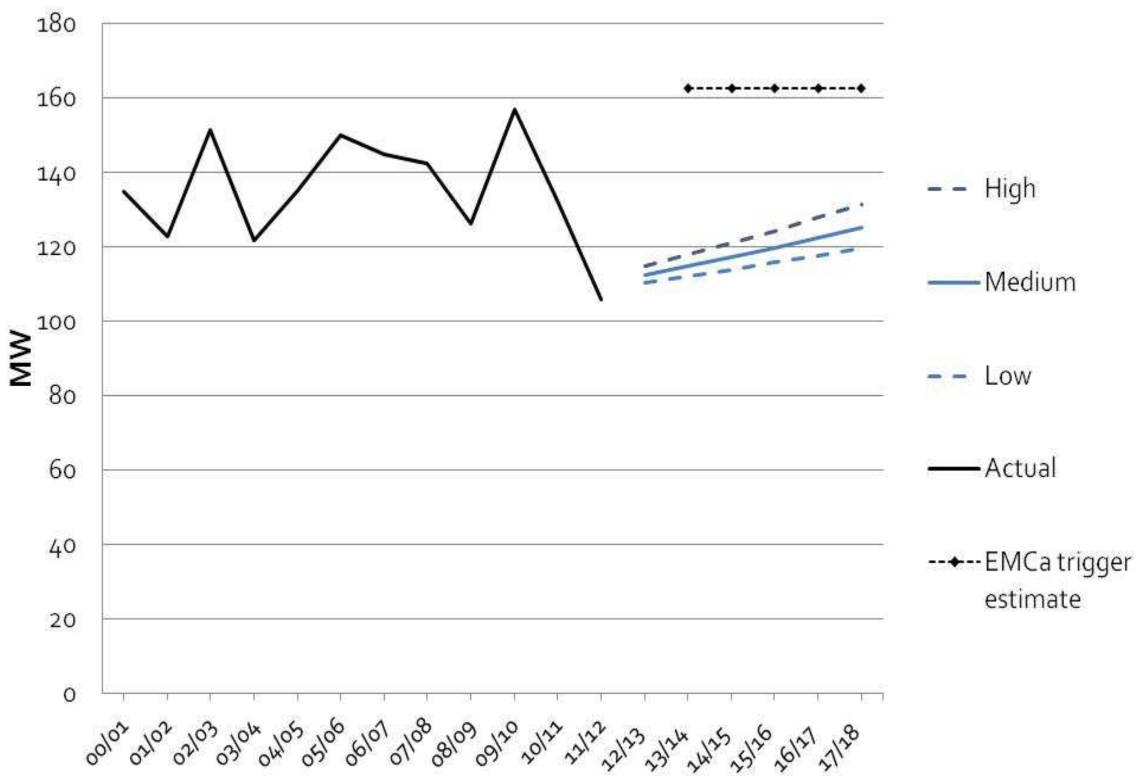
Projects for which the demand increase is not justified

ElectraNet proposed four projects for which it nominated a demand increase above its high demand scenariofor the 2013–18 regulatory control period as the trigger event:

- Southern Suburbs Reinforcement
- South East Connection Point Reinforcement
- South East Region Augmentation
- Lower South East Region Transformer Reinforcement.

As an example, Figure 13.4 shows historic demand compared to the demand required to trigger the Lower South East Region Transformer Reinforcement. A demand increase of 50 MW on 2012–13 numbers is required to trigger this project.

Figure 13.4 Lower South East Region Transformer reinforcement



Source: EMCa, *ElectraNet technical review*, October 2012, p. 153.

The AER does not accept these four contingent projects because ElectraNet did not explain why the demand increase is likely to occur. Therefore, the AER is not satisfied that:

- the projects are reasonably required to achieve the capex objectives[780]
- the trigger event is specific[781]

[780] NER, clause 6A.8.1(b)(1).
[781] NER, clause 6A.8.1(c)(1).

- the trigger event is all that is required for the revenue determination to be amended[782]
- the occurrence of the trigger event is probable during the 2013–18 regulatory control period.[783]

Projects driven by the expansion of Olympic Dam

Two of the proposed contingent projects are associated with the expansion of BHP Billiton's Olympic Dam mine:

- Upper Eyre Peninsula Reinforcement
- Northern Transmission Reinforcement – Load.

BHP Billiton announced on 22 August 2012 it has deferred its expansion of the Olympic Dam mine, pursuing an 'alternative, less capital–intensive' design instead.[784] EMCa advised that with the indefinite deferral of the expansion to the Olympic Dam mine, neither proposed contingent project as scoped appears probable.[785]

The Upper Eyre Peninsula Reinforcement project is triggered by a step change demand increase from BHP Billition. Without a step change increase in demand from BHP Billiton, this project is not reasonably required and the trigger event is not probable during the 2013–18 regulatory control period.

The AER considers that the Northern transmission reinforcement – load proposed contingent project has also been scoped on the basis of the Olympic Dam expansion occurring. EMCa also advised that even if demand increased to the corresponding trigger event level, it would not warrant a network reinforcement of the scale envisaged by the proposed contingent project.[786] The AER considers the proposed contingent project should be scoped to exclude the Olympic Dam load.

The AER considers these projects are not reasonably required to achieve the capex objectives during the 2013–18 regulatory control period. Further, even where some capex is expected, the scope of the proposed contingent projects as presented is unlikely to be required. For these reasons the AER does not accept these contingent projects which are driven by the expansion of BHP Billiton's Olympic Dam mine.

Market benefits projects with no specific driver

ElectraNet included proposed contingent projects for which it nominated completion of the regulatory investment test for transmission (RIT-T) as the sole trigger event. These projects are driven by market benefits.

The AER does not accept the following three proposed contingent projects because ElectraNet has not satisfied the AER that they are 'reasonably required' or that the occurrence of the trigger event is probable during the 2013–18 regulatory control period:

782 NER, clauses 6A.8.1(c)(4); 6A.8.2
783 NER, clause 6A.8.1(c)(5).
784 BHP Billiton, News release, 22 August 2012, http://www.bhpbilliton.com/home/investors/news/Pages/Articles/Olympic-Dam.aspx.
785 EMCa, *ElectraNet technical review*, October 2012, p. 151.
786 EMCa, *ElectraNet technical review*, October 2012, p. 151.

- Upper South East Generation Expansion—this project will be required if major generation proceeds in the upper South East, and the associated increase in power transfer would cause the existing 275kV lines to exceed their thermal ratings.[787]

- Torrens Island Switchyard Development—this project will allow for additional generation and reduce 66kV fault levels to allow for future 275kV augmentation.[788]

- Para—Brinkworth/Bungama Davenport 275kV transmission project—this project is proposed as generation expansion is seen to be a likely event in response to the number of new load developments proposed within the State and the prospect of increased export capability over the South East to Heywood interconnector.[789]

ElectraNet proposed that completion of the RIT-T should be the sole trigger for these proposed contingent projects.[790] The AER considers that completion of the RIT-T is a necessary and important part of the investment process. However, the RIT-T is a process rather than a definitive project trigger. The AER expects, however, that ElectraNet should be able to justify the inclusion of the contingent project by identifying the trigger for the project that will make it reasonably required.

For these three projects, ElectraNet did not identify that major generation is likely to occur. ElectraNet provided only a general reference to the possibility of generation capacity being installed. Further, ElectraNet did not provide detail of the likely energy requirements to be transferred in this part of the network which would trigger the contingent project. EMCa considered that the market benefits projects appear to be based on speculative assumptions by ElectraNet regarding possible and not probable locations of future generation.[791]

For these reasons, the AER does not accept these proposed contingent projects.

Eyre Peninsula connection point

ElectraNet's proposed contingent project, Eyre Peninsula connection point, is for the establishment of a nodal substation south of Cultana.[792] ElectraNet proposed that this project is triggered by a customer commitment to connect, or a demand increase of 5MW, and completion of the RIT–T.[793]

The AER considers that there may be a need for this contingent project. However, the trigger event must be all that is reasonably required for the revenue determination to be amended.[794] EMCa found that as presented, the Eyre Peninsula connection point project is not technically feasible because the project cannot occur until one or more other projects occur.[795] .

For these reasons, the AER does not accept the Eyre Peninsula connection point proposed contingent project.

13.4.3 Projects the AER considers might satisfy the NER requirements

The AER considers that five of ElectraNet’s proposed contingent projects might meet the NER requirements. The AER is satisfied these projects are uncertain.ElectraNet explained why it

787 ElectraNet, *Revenue proposal*, appendix Q, pp. 29–30.
788 ElectraNet, *Revenue proposal*, appendix Q, pp. 39–41.
789 ElectraNet, *Revenue proposal*, appendix Q, pp. 19–20.
790 ElectraNet, *Revenue proposal*, pp. 79–81.
791 EMCa, *ElectraNet technical review*, October 2012, p. 154.
792 ElectraNet, *Revenue proposal*, appendix Q, p. 3.
793 ElectraNet, *Revenue proposal*, appendix Q, p. 3.
794 NER, clause 6A.8.1(c)(4).
795 EMCa, *ElectraNet technical review*, October 2012, p. 155.

considered these projects are reasonably required, with specific reference to the underlying driver of the project.

However, the AER does not accept these contingent projects because the trigger events proposed for these contingent projects were not well defined and do not meet the NER requirements. The AER therefore proposed alternative trigger events for these projects.

The AER agrees that, with appropriate trigger events, the following proposed contingent projects (including the contingent capex amount) could be characterised as contingent projects:

- Davenport Reactive Support ($42 million)
- Mid North Connection Point ($59 million)
- Upper North Region Line Reinforcement ($62 million)
- Riverland Reinforcement ($407 million)
- South East to Heywood Interconnection upgrade ($96 million).

Trigger events must be specific and make undertaking the event reasonably necessary.[796] The TNSP should therefore be specific about the thermal or voltage limitations by comparison to the current position.

The trigger event must be the condition or event that generates increased costs and must be all that is required for the revenue determination to be amended.[797] The AER therefore considers that a trigger event needs to reflect the underlying driver of the project rather than refer to a consequence of the project driver occurring.

The AER requires ElectraNet to revise its project trigger definitions before the AER reconsiders these projects as contingent projects. The AER has set out indicative trigger events for these projects in Appendix C.

13.4.4 Other comments

In addition to the comments above, the AER identifies the following discrete issues which relate to specific projects:.

Lower Eyre Peninsula connection point

ElectraNet's Lower Eyre Peninsula connection point proposed contingent project, is for the reinforcement of the Eyre Peninsula network south of Cultana.[798] The Lower Eyre reinforcement is proposed as a $588 million project, to meet a demand trigger of a few MW.

The AER considers that the proposed contingent capex is an indicative amount; however the trigger event should be a condition or event that makes the undertaking of the proposed contingent project reasonably necessary.[799] EMCa considered that the scope of the Lower Eyre reinforcement project does not reflect the demand increase:[800]

[796] NER, clauses 6A.8.1(c)(1)–(2).
[797] NER, clause 6A.8.1(c)(3).
[798] ElectraNet *revenue proposal,* appendix Q, p. 6.
[799] NER, clause 6A.8.1(c)(2).
[800] EMCa, *ElectraNet technical review*, October 2012, p. 150.

> The Lower Eyre reinforcement is proposed as a $588m project, to meet a demand trigger of a few MW. In presentation, ElectraNet referred to the possibility of loads significantly in excess of this trigger that may arise if the reinforcement was to proceed; however evidence of such step loads was not provided. If such loads may fit the NER criteria, then an appropriate trigger could be specified that would encompass those loads. Alternatively, if the demand forecast is considered realistic and the project is not required to meet other much larger loads, then a considerably scaled-down project could be considered.

The Energy Consumers' Coalition of South Australia (ECCSA) also generally considered that the cost of the contingent projects compared to the amount of additional load appears excessive.[801]

The AER notes the comments from EMCa and the ECCSA and considers that ElectraNet has not substantiated how a demand increase of 5MW would make $588 million of capex reasonably necessary.

Riverland Reinforcement

ElectraNet's proposed contingent project, Riverland reinforcement, is for the construction of a new double circuit 275 kV transmission line and associate substation works to reinforce the Riverland region of South Australia.[802] ElectraNet proposed that this project would be triggered by a 12.5MW demand increase or publication that available dispatch into South Australia is insufficient to meet ETC reliability standards.[803]

The AER accepts that this could be included as a contingent project. The AER has set out a revised trigger events in appendix C. This project had two alternative trigger events. The AER does not accept the trigger that relates to a demand increase as ElectraNet has not identified the underlying driver of this project or explained why the occurrence of the trigger event is probable during the 2013–18 regulatory control period.

South East to Heywood Interconnection upgrade

The AER agrees, in principle, that the South East to Heywood Interconnection upgrade (Heywood) satisfies the NER requirements for contingent projects. However, the AER does not accept this project as a contingent project with the trigger event that has been defined by ElectraNet. As noted, the AER does not consider that completion of the RIT–T an appropriate trigger event.

ElectraNet stated that due to the growth in primarily renewable generation, the loading of transmission assets in the South East is being actively managed by AEMO to remain within thermal limits.[804] ElectraNet identified that economic generation dispatch is being impacted. As a consequence ElectraNet is working with AEMO on a joint RIT-T consultation process to investigate technically and economically feasible options to address these limitations.[805] Subsequent to lodging ElectraNet's Revenue Proposal, ElectraNet and AEMO published a draft RIT-T.[806]

EMCa advised that Heywood is 'likely to proceed' but found that there is uncertainty around the scope and cost of the solution.[807] The AER considers that after amending the trigger event, Heywood is likely to satisfy the NER requirements for contingent projects.

801 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 48.
802 ElectraNet, *Revenue proposal*, appendix Q, p. 12.
803 ElectraNet, *Revenue proposal*, appendix Q, p. 12.
804 ElectraNet, *Revenue proposal*, appendix Q, pp. 21–22.
805 ElectraNet. *Revenue proposal*, appendix Q, pp. 21–22.
806 South Australia – Victoria (Heywood) Interconnector Upgrade - RIT-T : Project Assessment Draft Report, available at http://www.aemo.com.au/Reports-and-Documents/Heywood-Interconnector-Upgrade-RITT-Project-Assessment-Draft-Report.
807 EMCa, *ElectraNet technical review*, October 2012, p. D-12.

Other submissions

The AER received several other submissions from stakeholders on contingent projects.

The South Australian Council of Social Service (SACOSS) noted that the contingent project list includes $2.5 billion in projects which is greater than the entire current RAB.[808] Further, even if only some of the contingent projects are triggered, then this will have a significant impact on capex, the RAB and the revenue requirement.[809]

The ECCSA stated that some contingent projects for the 2008–13 regulatory control period appear again in its proposal for the 2013–18 regulatory control period. The ECCSA also expressed concern that the proposed contingent capex has 'increased dramatically'.[810] Further, the forecast capex and contingent capex do not reflect the 'significant reduction' in demand forecasts.[811]

The AER notes that it also did not consider that any of the contingent projects as proposed were within the NER requirements.

13.5 Revisions

This sets out the changes (if any) the business needs to make to bring its proposal in line with the AER's decision.

Revision 13.1: make all necessary amendments to reflect the AER's draft decision

808 SACOSS, *Submission to the Australian Energy Regulator consultation on ElectraNet's 2013-18 transmission network revenue proposal*, August 2012, p. 4.
809 SACOSS, *Submission to the Australian Energy Regulator consultation on ElectraNet's 2013-18 transmission network revenue proposal*, August 2012, p. 4.
810 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 42.
811 ECCSA, *SA electricity transmission revenue reset, ElectraNet SA application*, August 2012, p. 49.

14 Pricing methodology

This attachment sets out the Australian Energy Regulator's (AER) determination on the pricing methodology that the transmission network service provider (TNSP) ElectraNet proposed for the 2013–18 regulatory control period.[812] A pricing methodology is a method, formula, process or approach that:

- allocates the aggregate annual revenue requirement (AARR) to the categories of prescribed transmission services that the TNSP provides and to the network connection points of network users;[813] and
- determines the structure of prices that a TNSP may charge for each category of prescribed transmission services.[814]

Two TNSPs provide prescribed transmission services in South Australia: ElectraNet and Murraylink. Under the National Electricity Rules (NER), if more than one TSNP provides prescribed transmission services in a region, then those providers must appoint a coordinating network service provider that is responsible for allocating all relevant AARR in that region.[815] In South Australia, ElectraNet was appointed the coordinating network service provider, and so is responsible for allocating both ElectraNet's and Murraylink's AARR.

14.1 Draft decision

The AER approves the pricing methodology proposed by ElectraNet for the 2013-18 regulatory control period. It is satisfied the proposed pricing methodology:

- gives effect to, and complies with, the pricing principles for prescribed transmission services; and
- complies with the information requirements of the pricing methodology guidelines.[816]

14.2 ElectraNet's proposal

On 31 May 2012, ElectraNet submitted its proposed pricing methodology for the 2013–18 regulatory control period. The AER assessed ElectraNet's proposed pricing methodology as being largely the same as its existing methodology (which applies until 30 June 2013).[817] This is with the exception of two proposed changes:

- the modification of ElectraNet's priority ordering methodology; and
- the introduction of standby service arrangements with network customers.

ElectraNet proposed to modify its priority ordering methodology to incorporate the amendments to clause 11.6.11 of the NER. The changes introduced by that amendment relate to the cost allocation of assets grandfathered as prescribed transmission services.[818] ElectraNet submitted that the timing of the amendment makes the modification to its priority ordering methodology necessary. The changes

812 NER, clause 6A.2.2(4).
813 NER, clause 6A.24.1(b)(1).
814 NER, clause 6A.24.1(b)(2).
815 NER, clause 6A.29.1(a).
816 NER, clause 6A.24.1(c).
817 ElectraNet, *Revised proposed pricing methodology 1 July 2008 to 30 June 2013*, December 2007.
818 Australian Energy Market Commission (AEMC), *Rule determination: National electricity amendment (cost allocation arrangements for transmission services) Rule 2009* (Rule proponent: National Generators Forum), 29 January 2009.

to clause 11.6.11 took effect in 2009,[819] whereas ElectraNet submitted its existing pricing methodology to the AER for approval in December 2007.[820]

Standby service arrangements allow network customers to contract to an agreed maximum demand under normal operating conditions and a greater demand on a standby basis. If approved, it would allow some network customers to increase their load above the agreed maximum demand in their connection agreement without incurring a penalty. The availability of this arrangement would be subject to the discretion of ElectraNet and the operational conditions of the transmission network. Other features of its standby service arrangement include the following:[821]

- the transmission network would be planned and developed to satisfy the contract agreed maximum demand rather than the standby amount.
- the customer's connection agreement must specify the conditions for temporarily varying from the contracted agreed maximum demand.
- when a standby service arrangement has been agreed between ElectraNet and a customer, the customer's connection agreement must specify an agreed maximum demand and the conditions under which an excess demand charge will apply.

ElectraNet noted in its proposed pricing methodology that Murraylink has appointed it as the coordinating network service provider in South Australia.[822] ElectraNet also stated that Murraylink must advise ElectraNet annually of the AARR for its transmission assets, along with any other information reasonably required.[823]

14.3 Assessment approach

The AER must approve a TNSP's proposed pricing methodology if it is satisfied that the methodology:

- gives effect to, and complies with, the pricing principles for prescribed transmission services[824]
- complies with the information requirements of the pricing methodology guidelines.[825]

ElectraNet's proposed pricing methodology is largely the same as its existing methodology.[826] The AER's assessment therefore focused on the changes ElectraNet proposed to introduce in the 2013–18 regulatory control period.

14.4 Reasons for draft decision

The AER approves ElectraNet's proposed pricing methodology because it meets the requirements of the pricing principles and the pricing methodology guidelines.[827] Where necessary, it also incorporated other requirements in the NER.

819 AEMC, *Rule determination: National electricity amendment (cost allocation arrangements for transmission services) Rule 2009* (Rule proponent: National Generators Forum), 29 January 2009.
820 ElectraNet, *Revised proposed pricing methodology 1 July 2008 to 30 June 2013*, December 2007
821 ElectraNet, *Proposed pricing methodology for 1 July 2013 to 30 June 2018*, May 2012, p. 17.
822 ElectraNet, *Proposed pricing methodology for 1 July 2013 to 30 June 2018*, May 2012, p. 4.
823 ElectraNet, *Proposed pricing methodology for 1 July 2013 to 30 June 2018*, May 2012, p. 4.
824 NER, clause 6A.14.3(g)(1).
825 NER, clause 6A.14.3(g)(2).
826 ElectraNet, *Revised proposed pricing methodology 1 July 2008 to 30 June 2013*, December 2007
827 NER, clauses 6A.14.3(g)(1)–(2).

14.4.1 The proposed changes

Priority ordering methodology

The priority ordering methodology proposed by ElectraNet complies with the NER. As with its existing pricing methodology (applicable until 30 June 2013) ElectraNet adopted the approach in clause 6A.23.2(d). This clause provides that where the costs of a transmission asset are attributable to more than one service category those costs will be allocated according to the following order:

- first allocate to prescribed transmission use of system (TUOS) services, but only to the extent of the standalone amount for that category
- if any portion of the costs is not allocated to prescribed TUOS services, then allocate to providing prescribed common transmission services, but only to the extent of the standalone amount for that category
- if any portion of the costs is not allocated to providing prescribed TUOS services or prescribed common transmission services, then allocate to providing prescribed entry service and prescribed exit services.[828]

ElectraNet's proposed modification seeks to incorporate, in its existing priority ordering methodology, amendments to NER clause 11.6.11. This amendment addressed the cost allocation of assets that provide prescribed transmission services under grandfathering arrangements.[829] These assets are termed 'existing assets' and 'replacement assets'.[830]

The AER is satisfied that ElectraNet has given effect to the changes introduced by the amendment to clause 11.6.11 by applying the relevant parts of that clause (as it is currently worded) in Appendix E of its proposed pricing methodology.[831] In particular, it included an additional step in the priority ordering process headed: 'Allocation of Prescribed Entry and Exit Service costs to prescribed TUOS services per 11.6.11'.[832] This additional step complies with the amended clause 11.6.11(c) of the NER, which requires the cost of existing or replacement assets providing prescribed TUOS services to retain that service classification. This applies even if those costs would otherwise be attributable to prescribed entry or exit services.[833] The AER considers the incorporation of the amendment to clause 11.6.11 to be necessary to update ElectraNet's proposed pricing methodology with relevant changes to the NER.

Standby service arrangement

The introduction of standby services would modify the current arrangements for when a network customer temporarily increases its energy use above the agreed maximum demand (AMD). Instead of paying a penalty, a network customer with a standby service would pay ElectraNet a higher network charge incremental to the cost of providing the increased demand. This arrangement would only be available during specified circumstances in a connection agreement and would be subject to the operational conditions of the network. ElectraNet would also not be obligated to provide a standby service requested by a customer.

828 NER, clause 6A.23.2(d)(3).
829 AEMC, *Rule determination: National electricity amendment (cost allocation arrangements for transmission services) Rule 2009* (Rule proponent: National Generators Forum), 29 January 2009
830 NER. clause 11.6.11(a).
831 ElectraNet, *Proposed pricing methodology for 1 July 2013 to 30 June 2018*, May 2012, p. 28.
832 ElectraNet, *Proposed pricing methodology for 1 July 2013 to 30 June 2018*, May 2012, p. 31.
833 NER, clause 11.6.11(c).

The standby service arrangement may lead to improved pricing outcomes by providing a limited exemption to the excess demand charge, which is ordinarily payable by a network customer if actual demand exceeds its AMD. The excess demand charge rate ($/kW) is calculated as three times the maximum revenue that ElectraNet can earn from prescribed transmission services during the pricing period, divided by the aggregate of all contracted demands connected to the network.[834] That rate ($/kW) is then multiplied by the energy consumed (kW) by a network customer over the AMD.[835] Liability under an excess demand charge, therefore, does not reflect the cost to ElectraNet of providing prescribed transmission services. Rather, the excess demand charge is a penalty intended to encourage network customers to restrict their energy consumption to a contracted amount. This arrangement manages the reliability of the network; however, in some cases improved pricing outcomes may be possible by substituting the excess demand charge for a standby service.

For example, improved pricing outcomes may be achieved by a network customer with an onsite generator. With ElectraNet's consent, this customer would be able to contract to an AMD under normal operating conditions and a greater standby demand that covers its increased energy needs should its generator become unavailable. Under the standby service arrangement the customer would avoid the imposition of an excess demand charge while its generator is out of service and instead pay a network fee reflective of ElectraNet's costs of providing the additional load. This arrangement would only be offered when network utilisation by other customers is low. It thus provides an improved pricing outcome that incorporates the performance capabilities of ElectraNet's network at off peak times and the needs of some transmission customers to temporarily increase their network use above their AMD.

The AER approves the introduction of standby service arrangements in ElectraNet's proposed pricing methodology since it is likely to lead to improved pricing outcomes. The service also complies with the high level pricing principles in the NER,[836] which are intended to promote innovative pricing arrangements.[837]

14.4.2 Assessment against the pricing principles

The AER considers the pricing methodology proposed by ElectraNet meets the requirements of the pricing principles. The NER pricing principles are intended to provide scope for TNSPs to develop transmission pricing arrangements that address the circumstances in which they operate their network,[838] which limit the AER's review to a high level assessment. Table 14.1 and Table 14.2 contain the AER's reasoning involving ElectraNet's methodology for allocating the AARR and the annual service revenue requirement (ASRR). Table 14.3 sets out the AER's assessment of the proposed pricing structure.

Calculation of the AARR, and its allocation to categories of prescribed transmission services

The AER assessed ElectraNet's proposed pricing methodology for calculating and allocating the AARR, and considers that the proposal meets the NER requirements. Table 14.1 summarises the AER's assessment.

[834] ElectraNet, *Proposed pricing methodology for 1 July 2008 to 30 June 2013*, May 2012, p. 12.
[835] ElectraNet, *Proposed pricing methodology for 1 July 2008 to 30 June 2013*, May 2012, p. 11.
[836] NER, clause 6A.23.4.
[837] AEMC, *Rule Determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No 22*, 21 December 2006, pp. 27–8.
[838] AEMC, *Rule Determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No 22*, 21 December 2006, pp. 27–8.

Table 14.1 ElectraNet's proposed calculation and allocation of the AARR, and the NER requirements

NER requirements	AER assessment
Requirement for the AARR to be calculated as defined in the NER—clause 6A.22.1	Clause 6.3 of ElectraNet's proposed pricing methodology satisfies this requirement.
Requirement for the AARR to be allocated to each category of prescribed transmission services in accordance with attributable cost share for each such category of service—clause 6A.23.2(a)	Clauses 6.5–6.7 and appendixes A, B and E of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for every portion of the AARR to be allocated and for the same portion of AARR not to be allocated more than once—clause 6A.23.2(c)	Clauses 6.5–6.7 and appendixes A, B and E of ElectraNet's proposed pricing methodology satisfy this requirement.
Subject to clause 11.6.11 of the NER, requirement for adjusting attributable cost share and priority ordering approach to asset costs that would otherwise be attributed to the provision of more than one category of prescribed transmission services—clause 6A.23.2(d)	Clauses 6.5–6.7 and appendixes A, B and E of ElectraNet's proposed pricing methodology satisfy this requirement.

Allocation of the ASRR to transmission network connection points

The AER assessed ElectraNet's proposed pricing methodology for allocating the ASRR, and considers it meets the NER requirements. Table 14.2 summarises the AER's assessment.

Table 14.2 ElectraNet's proposed allocation of the ASRR, and the NER requirements

NER requirements	AER assessment
Requirement for whole ASRR for prescribed entry services to be allocated to transmission network connection points in accordance with the attributable connection point cost share for prescribed entry services that are provided by the TNSP at that connection point—clause 6A.23.3(a)	Clauses 6.1–6.9 and appendix B of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for the whole ASRR prescribed exit services to be allocated to transmission network connection points in accordance with the attributable connection point cost share for prescribed exit services that are provided by the TNSP at that connection point—clause 6A.23.3(b)	Clauses 6.1–6.9 and appendix B of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for the allocation of the ASRR for: prescribed TUOS services locational components pre-adjusted nonlocational components —clause 6A.23.3(c)	Clauses 6.1–6.9 and appendixes B and E of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for adjusting attributable cost share and priority ordering approach to asset costs that would otherwise be attributed to the provision of more than one category of prescribed transmission services—clause 6A.23.2(d)	Clauses 6.1–6.8 and appendix B of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for the recovery of the ASRR for prescribed common transmission services and the operating and maintenance costs incurred in the provision of those services to be recovered through prices charged to transmission customers and network service and network service provider transmission connection points set in accordance with price structure principles set out in clause 6A.23.4—clause 6A.23.3(f)	Clauses 6.1–6.9 of ElectraNet's proposed pricing methodology satisfy this requirement.

Development of price structure

The AER assessed ElectraNet's proposed pricing methodology and process for developing different prices for recovering the ASRR, and considers the proposal meets the NER requirements. Table 14.3 sets out the AER's assessment.

Table 14.3 ElectraNet's proposed pricing structure and the NER requirements

NER requirements	AER assessment
Requirement for separate prices for each category of prescribed transmission services—clause 6A.23.4(b)	Clause 6.11 and appendix A of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for fixed annual amount prices for prescribed entry services and prescribed exit services—clause 6A.23.4(c)	Clause 6.11.1 and appendix A of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for postage stamped prices for prescribed common transmission services—clause 6A.23.4(d)	Clause 6.11.3 and appendix A of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for prices for locational component of prescribed TUOS services to be based on demand at times of greatest use of the transmission network and for which network investment is most likely to be contemplated—clause 6A.23.4(e)	Clause 6.11.2 and appendix A of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for prices for the locational component of ASRR for prescribed TUOS services not to change by more than 2 per cent per year compared with the load weighted average prices for this component for the relevant region—clause 6A.23.4 to clause 6A.23.4(f)	Clause 6.11.2 and appendix A of ElectraNet's proposed pricing methodology satisfy this requirement.
Requirement for prices for the adjusted nonlocational component of prescribed TUOS services to be on a postage stamp basis—clause 6A.23.4(j)	Clause 6.11.3 and appendix A of ElectraNet's proposed pricing methodology satisfy this requirement.

14.4.3 Assessment against the pricing methodology guidelines

The AER is satisfied that the proposed pricing methodology complies with the information requirements of the pricing methodology guidelines. Key features of the proposal include:

- acknowledging that ElectraNet is the coordinating network service provider responsible for allocating ElectraNet's and Murraylink's AARR
- calculating the locational component of prescribed TUOS services costs using a cost reflective network pricing methodology
- basing the locational prescribed TUOS services price on an agreed nominated demand and the average half hourly demand
- basing the postage stamp pricing structure for the non-locational component of prescribed TUOS services and prescribed common transmission services on contract agreed maximum demand or historical energy
- using the priority ordering approach under clause 6A.23.3(d) of the NER to implement priority ordering
- describing how asset costs that may be attributable to both prescribed entry services and prescribed exit services will be allocated at a connection point
- describing billing arrangements as in clause 6A.27 of the NER
- describing prudential requirements as in clause 6A.28 of the NER

- including hypothetical examples
- describing how ElectraNet intends to monitor and develop records of its compliance with its approved pricing methodology.

15 Negotiated services

The Australian Energy Regulator's (AER) transmission determination imposes control over revenues that a transmission network service provider (TNSP) can recover from the provision of prescribed transmission services. Negotiated transmission services do not have their terms and conditions determined by the AER. Under the National Electricity Rules (NER), these services are subject to negotiation between parties, or alternatively arbitration and dispute resolution by a commercial arbitrator. These processes are facilitated by:[839]

- a negotiating framework; and
- negotiated transmission service criteria (NTSC).

A TNSP must prepare a negotiating framework which sets out procedures for negotiating the terms and conditions of access to a negotiated transmission service.[840] The NTSC set out criteria that a TNSP must apply in negotiating terms and conditions of access, including the prices and access charges for negotiated transmission services.[841] They also contain the criteria that a commercial arbitrator must apply to resolve disputes about such terms and conditions and/or access charges.[842] This attachment sets out the AER’s considerations and conclusions on ElectraNet’s proposed negotiating framework and NTSC.

15.1 Draft decision

The AER does not approve ElectraNet’s proposed negotiating framework because the proposal does not comply with the NER requirements in clause 6A.9.5(c). The following paragraphs of the proposed negotiating framework should be amended:

- paragraph 6.3.1, which seeks to give effect to sub-clauses 6A.9.5(c)(3)(i) and(ii) of the NER
- paragraph 7.2, which contains a citation error in referencing another part of ElectraNet’s proposed negotiating framework
- paragraph 9.1.1, which seeks to give effect to clause 6A.9.5(c)(5) of the NER.

The AER’s draft decision is that the AER's proposed NTSC for ElectraNet published in June 2012 will apply to ElectraNet in the 2013–18 regulatory control period. The proposed NTSC gives effect to the negotiated transmission service principles set out in clause 6A.9.1 of the NER.

15.2 ElectraNet’s proposal

In accordance with the NER, ElectraNet submitted its proposed negotiating framework with its revenue proposal for the 2013-18 regulatory control period.[843] The AER assessed ElectraNet's proposed negotiating framework to be largely the same as its existing framework (which applies until 30 June 2013). This includes paragraph 6.3.1 which, although it does not vary from its existing framework,[844] adopts the same wording that the AER refused to approve in a previous transmission

839 NER, clause 6A.9.2.
840 NER, clause 6A.9.5(a).
841 NER, clause 6A.9.4(a)(1).
842 NER, clause 6A.9.4(a)(2).
843 NER, clause 6A.10.1. ElectraNet submitted its revenue proposal to the AER on 31 May 2012.
844 ElectraNet, *Proposed negotiating framework for 1 July 2008 to 30 June 2013*, May 2007, p. 9.

determination.[845] The Clean Energy Council (CEC) has also suggested that paragraph 9.1.1, which relates to the suspension of negotiations, should be amended.[846]

In June 2012, the AER published on its website the AER's proposed NTSC (reproduced in section 15.6) that would apply to ElectraNet as required by clause 6A.11.3 of the NER.[847]

15.3 Assessment approach

For the AER to approve it, a proposed negotiating framework must specify each requirement in clause 6A.9.5(c) of the NER (summarised in Table 15.1). The AER examined whether ElectraNet's proposed negotiating framework met these requirements.

The AER considers a set of NTSC that adopt the negotiated transmission service principles would satisfy the NER requirements. It thus assessed whether the proposed NTSC reflect the negotiating transmission service principles in clause 6A.9.1 of the NER.

15.4 Reasons for draft decision

The AER does not approve ElectraNet's proposed negotiating framework because it does not accurately specify the requirements of clause 6A.9.5(c) the NER. In particular, clause 6A.9.5(c)(5) and sub-clauses 6A.9.5(c)(3)(i) and (ii) of the NER are not accurately reflected in ElectraNet's proposed negotiating framework. The proposed negotiating framework also contains a citation error in paragraph 7.2.

The AER determines that the AER's proposed NTSC (reproduced in section 15.6) will apply to ElectraNet because the criteria give effect to the negotiating transmission principles in clause 6A.9.1 of the NER.

15.4.1 Negotiating framework

Sub-clause 6A.9.5(c)(3)(i) and (ii)

Sub-clauses 6A.9.5(c)(3)(i) and(ii) of the NER requires a TNSP:

i. to identify and inform a service applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiated transmission service; and

ii. to demonstrate to a service applicant that the charges for providing the negotiated transmission service reflect those costs and/or the cost increment or decrement (as appropriate).

Paragraph 6.1.3 of the proposed negotiating framework seeks to give effect to the above clause by stating that ElectraNet must provide a service applicant with:[848]

> The reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiated Transmission Service to the Service Applicant which demonstrate to the Service Applicant that the charge for providing the Negotiated Transmission Service reflect those costs and/or the cost increment or decrement.

845 AER, *Draft decision: Powerlink transmission determination 2012-13 to 2016-17*, 29 November 2011, p. 335.
846 Clean Energy Council, *Submission to the AER on the 2013–18 ElectraNet determination,* 27 August 2012, p. 7.
847 AER, *Proposed negotiating transmission service criteria for ElectraNet, Regulatory control period 1 July 2013 to 30 June 2018*, June 2012: http://www.aer.gov.au/node/16617.
848 ElectraNet, *Proposed negotiating framework for 1 July 2013 to 30 June 2018*, May 2012, p. 10 .

This paragraph adopts the same wording as Powerlink's proposed negotiating framework for the 2012–17 regulatory control period, which the AER rejected in its draft decision.[849] Sub-clauses 6A.9.5(c)(3)(i) and (ii) contain two separate but related obligations. The drafting in Electranet's proposed paragraph 6.3.1 assumes that ElectraNet's costs are reasonable and that this demonstrates that the charge reflects those costs. It is not clear from ElectraNet's proposal that ElectraNet must first identify and inform the service applicant of those costs and then demonstrate how a proposed charge reflects the reasonable cost of providing a negotiated service. The CEC noted this in its submissions to the AER, stating that 'the NER stipulates that the TNSP must disclose its costs to provide the service and then demonstrate the charges to the Service Applicant are reflective of those costs, as two separate stages'.[850] The AER considers that paragraph 6.1.3 should be amended as indicated in Revision 15.1.

Minor citation error

The AER also considers that ElectraNet made a citation error. Paragraph 7.2 of ElectraNet's proposed negotiating framework provides:[851]

> ElectraNet must use its reasonable endeavours to provide ... commercial information requested by the Service Applicant ... within 10 Business Days of the date of the request under paragraph 5.1.

Reference to paragraph 5.1 appears to be an error. That paragraph is about a service applicant providing information to ElectraNet, not ElectraNet providing information to a service applicant. The AER considers that the proposed negotiating framework should be amended as indicated in Revision 15.2.

Clause 6A.9.5(c)(5)

Clause 6A.9.5(c)(5) of the NER states that a negotiating framework must provide:

> A reasonable period of time for commencing, progressing and finalising negotiations with a *Service Applicant* for the provision of the *negotiated transmission service*, and a requirement that each party to the negotiation must use its reasonable endeavours to adhere to those time periods during negotiations.

This clause contains two requirements: the specification of a reasonable period of time for negotiations and a requirement that each party use their reasonable endeavours to adhere to those time periods. The AER considers the first requirement to be met by paragraph 3 of ElectraNet's proposed negotiating framework which sets out a reasonable timeframe for negotiations. The AER also considers paragraph 9.1.1 of the proposed negotiating framework seeks to give effect to the second requirement in clause 6A.9.5(c)(5) of the NER by stating that the negotiating timeframe is suspended if:[852]

> within 15 Business Days of ElectraNet providing the Commercial Information to the Service Applicant pursuant to paragraph 6.1, the Service Applicant does not formally accept that Commercial Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations

The CEC submission referred to paragraph 9.1.1 of ElectraNet's proposed negotiating framework and stated that 'while this is an important aspect to ensuring the agreed timeframe is adhered to it is also equally as important to recognise that there are two information flow paths'.[853] That is, the CEC considers that if ElectraNet is able to suspend negotiations where receipt of commercial information is

849 AER, *Draft decision: Powerlink transmission determination 2012-13 to 2016-17*, 29 November 2011, p. 335.
850 Clean Energy Council, *Submission to the AER on the 2013–18 ElectraNet determination*, 27 August 2012, p. 7
851 ElectraNet, *Proposed negotiating framework for 1 July 2013 to 30 June 2018*, May 2012, pp. 10–11.
852 ElectraNet, *Proposed negotiating framework for 1 July 2013 to 30 June 2018*, May 2012, p. 11
853 Clean Energy Council, *Submission to the AER on the 2013–18 ElectraNet determination*, 27 August 2012, p. 7

not formally accepted then a similar right to suspend negotiations should also be available to a service applicant. The AER agrees with this submission and determines that paragraph 9.1.1 should be amended so that negotiations are also suspended if ElectraNet does not formally accept commercial information provided by a service applicant within 15 business days. This more accurately reflects clause 6A.9.5(c)(5) which requires 'each party to use its reasonable endeavours (emphasis added)' to adhere to time periods for commencing, progressing and finalising negotiations for a negotiated service. The AER thus considers paragraph 9.1.1 of the negotiating framework should be amended as indicated in revision 15.3.

Table 15.1 AER's assessment of the negotiating framework proposed by ElectraNet

NER requirements	AER assessment
Requirement for ElectraNet and the applicant of a negotiated transmission service to negotiate in good faith—clause 6A.9.5(c)(1)	Paragraph 2 of ElectraNet's proposed negotiating framework satisfies this requirement. It states: 'ElectraNet and the Service Applicant should negotiate in good faith the terms and conditions of access for the provision by ElectraNet of the Negotiated Transmission Service sought by the Service Applicant'.
Requirement for ElectraNet to provide all such commercial information reasonably required to enable the applicant of a negotiated transmission service to engage in effective negotiations—clause 6A.9.5(c)(2)	Paragraphs 6 and 7 of ElectraNet's proposed negotiating framework seek to address this requirement. However, paragraph 7.2 contains a minor citation error that requires amending.
Requirement for ElectraNet to identify and inform the negotiated transmission service applicant of the reasonable costs of providing the negotiated service; and demonstrate that charges reflect costs—clause 6A.9.5(c)(3)	Paragraph 6.1.3 of ElectraNet's proposed negotiating framework seeks to address this requirement. However, paragraph 6.1.3 is not sufficiently clear to satisfy the NER requirements. The AER's consideration of this issue is discussed above.
Requirement for a negotiated transmission service applicant to provide all such commercial information reasonably required to enable ElectraNet to engage in effective negotiation—clause 6A.9.5(c)(4)	Paragraphs 4 and 5 of ElectraNet's proposed negotiating framework satisfy this requirement.
Requirement to specify a reasonable period of time for commencing, progressing and finalising negotiations; and a requirement for each party to use their reasonable endeavours to adhere to those time periods during the negotiation—clause 6A.9.5(c)(5)	Paragraphs 3 of the proposed negotiating framework sets out a compliant timeframe for progressing negotiations. Paragraph 9 should be amended to reflect the fact that there are two information flows during negotiations (as discussed above).
Requirement to specify a process for disputes to be dealt with in accordance with the relevant provisions for dispute resolution[854]—clause 6A.9.5(c)(6)	Paragraph 10 of ElectraNet's proposed negotiating framework satisfies this requirement. It specifies that all disputes between the parties are to be dealt with in accordance with Part K of Chapter 6A of the NER.
Requirement to specify arrangements for the payment of ElectraNet's reasonable direct expenses incurred in processing the application to provide the negotiated transmission service—clause 6A.9.5(c)(7)	Paragraph 11 of ElectraNet's proposed negotiating framework satisfies this requirement.
Requirement for ElectraNet to determine the potential impact of the provision of a negotiated transmission service on other network users—clause 6A.9.5(c)(8)	Paragraph 8 of ElectraNet's proposed negotiating framework satisfies this requirement.
Requirement for ElectraNet to notify and consult with any affected network user and ensure the negotiated transmission service does not result in noncompliance with obligations in relation to other network users under the NER—clause 6A.9.5(c)(9)	Paragraph 8.2 of ElectraNet's proposed negotiating framework satisfies this requirement. It states: 'ElectraNet should notify and consult with any affected Transmission Users to ensure that the provision of the Negotiated Transmission Service does not result in non-compliance with obligations in relation to other Transmission Network Users under the NER'.

[854] The relevant provisions for dispute resolution are set out in part K of chapter 6A of the NER.

15.4.2 Negotiated transmission service criteria

The AER determines that the proposed NTSC published in June 2012 will apply to ElectraNet in the 2013-18 regulatory control period. The NTSC adopt the negotiated transmission service principles in clause 6A.9.1 of the NER and thus directly reflect the requirements of the NER.

The CEC suggested amendments to paragraphs three and five. Paragraph three of the proposed NTSC states:[855]

> The terms and conditions of access for negotiated transmission services, particularly any exclusions and limitations of liability and indemnities, must not be unreasonably onerous. Relevant considerations include the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the cost to the TNSP of providing the negotiated service.

The CEC suggested that the AER should include a reasonableness test in paragraph three of the proposed NTSC. The AER does not accept this submission. Paragraph three already includes a reasonableness test by requiring that the terms and conditions of access for transmission services must not be 'unreasonably onerous'. The AER is also not satisfied that paragraph three lacks sufficient detail, as suggested by the CEC.[856] Paragraph three includes a non-exhaustive list of relevant considerations to assist in determining whether the terms and conditions are unreasonably onerous. These are 'the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the cost to the TNSP of providing the negotiated service'.[857] The AER thus considers paragraph three of the proposed NTSC meets the NER requirements and contains sufficient detail, having incorporated all of the elements in clause 6A.9.1(10).

The CEC also submitted that paragraph five of the proposed NTSC does not align with clause 6A.9.5(c)(3) of the NER and should be amended as follows (CEC's proposed amendments underlined):[858]

> The price of a negotiated transmission service must <u>be shown to efficiently</u> reflect the cost that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology.

The AER does not consider there to be a need for the proposed NTSC to align with clause 6A.9.5(c)(3) of the NER. That clause relates to the requirements of a TNSP's proposed negotiating framework rather than a proposed NTSC. The CEC's concern is also addressed in section 15.4.1 of this attachment which identifies that ElectraNet's proposed negotiating framework does not fully reflect clause 6A.9.5(c)(3) of the NER and must be amended as indicated at Revision 14.1.

The approved NTSC is reproduced in section 15.6.

15.5 Revisions

The AER does not approve the negotiating framework proposed by ElectraNet. It requires ElectraNet to amend the proposed negotiating framework and resubmit a revised proposed negotiating framework in accordance with clause 6A.12.3(a)(2) for the AER's final decision . The AER would accept the following changes if ElectraNet submits a revised negotiating framework to the AER.

[855] Clean Energy Council, *Submission to the AER on the 2013–18 ElectraNet determination*, 27 August 2012, p. 4.
[856] Clean Energy Council, *Submission to the AER on the 2013–18 ElectraNet determination*, 27 August 2012, p. 4.
[857] AER, *Proposed negotiating transmission service criteria for ElectraNet, Regulatory control period 1 July 2013 to 30 June 2018*, June 2012: http://www.aer.gov.au/node/16617.
[858] Clean Energy Council, *Submission to the AER on the 2013–18 ElectraNet determination*, 27 August 2012, p. 4.

Revision 15.1: paragraph 6.1.3 of the proposed negotiating framework should be amended to read:

(i) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiated transmission service to the Service Applicant, and

(ii) demonstration to the Service Applicant that the charges for providing the negotiated transmission service reflect those costs and/or the increase or decrease.

Revision 15.2: paragraph 7.2 of the proposed negotiating framework should be amended to read:

ElectraNet must use its reasonable endeavours to provide the Service Applicant with the Commercial Information requested by the Service Applicant in accordance with paragraph 7.1 within 10 Business Days of the date of the request under paragraph 7.1, or such other period as agreed by the parties.

Revision 15.3: paragraph 9.1 of the proposed negotiating framework should be amended to read:

The timeframes for negotiations of provision of a Negotiated Transmission Service as contained within this negotiating framework, or as otherwise agreed between the parties, are suspended if:

9.1.1 (a) within 15 Business Days of ElectraNet providing the Commercial Information to the Service Applicant pursuant to paragraph 6.1 or 7.1, the Service Applicant does not formally accept that Commercial Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations;

9.1.1 (b) within 15 Business Days of a Service Applicant providing the Commercial Information to the ElectraNet pursuant to paragraph 4.1 or 5.1, ElectraNet does not formally accept that Commercial Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations

15.6 Negotiating transmission service criteria

This section reproduces the proposed NTSC for ElectraNet published by the AER in June 2012.

15.6.1 National Electricity Objective

1. The terms and conditions of access for a negotiated transmission service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

15.6.2 Criteria for terms and conditions of access

Terms and conditions of access

2. The terms and conditions of access for a negotiated transmission service must be fair, reasonable, and consistent with the safe and reliable operation of the power system in accordance with the NER.

3. The terms and conditions of access for negotiated transmission services, particularly any exclusions and limitations of liability and indemnities, must not be unreasonably onerous. Relevant considerations include the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the cost to the TNSP of providing the negotiated service.

4. The terms and conditions of access for a negotiated transmission service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of services

5. The price of a negotiated transmission service must reflect the cost that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology.

6. Subject to criteria 7 and 8, the price for a negotiated transmission service must be at least equal to the avoided cost of providing that service but no more than the cost of providing it on a stand alone basis.

7. If the negotiated transmission service is a shared transmission service that:

    i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or

    ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER

then the difference between the price for that service and the price for the shared transmission service which meets network performance requirements must reflect the TNSP's incremental cost of providing that service (as appropriate).

8. For shared transmission services, the difference in price between a negotiated transmission service that does not meet or exceed network performance requirements and a service that meets those requirements should reflect the TNSP's avoided costs. Schedule 5.1 and 5.1a of the NER or any relevant electricity legislation must be considered in determining whether any network service performance requirements have not been met or exceeded.

9. The price for a negotiated transmission service must be the same for all Transmission Network Users. The exception is if there is a material difference in the costs of providing the negotiated transmission service to different Transmission Network Users or classes of Transmission Network Users.

10. The price for a negotiated transmission service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person. In such cases, the adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

11. The price for a negotiated transmission service must be such as to enable the TNSP to recover the efficient costs of complying with all regulatory obligations associated with the provision of the negotiated transmission service.

15.6.3 Criteria for access charges

Access charges

12. Any access charges must be based on the costs reasonably incurred by the TNSP in providing Transmission Network User access. This includes the compensation for foregone revenue referred to in clause 5.4A(h)–(j) of the NER and the costs that are likely to be incurred by a person referred to in clause 5.4A(h)–(j) of the NER (as appropriate).

16 Cost pass throughs

The pass through mechanism of the National Energy Rules (NER) recognises that a transmission network service provider (TNSP) can be exposed to risks beyond its control, which may have material impact on its costs. A cost pass through enables a business to recover (or pass through) the costs of defined unpredictable, high-cost events which are not built into the transmission determination.

The NER specifies certain pass through events that are applicable to all TNSPs:[859]

- a regulatory change event
- a service standard event
- a tax change event
- an insurance event.[860]

In August 2012, the Australian Energy Market Commission (AEMC) changed the NER's cost pass through provisions to give TNSPs the ability to nominate additional pass through events as part of their revenue proposals.[861]

This chapter sets out the AER’s draft decision about which of ElectraNet's three nominated pass through events it will accept as an additional pass through event for the regulatory control period.[862]

16.1 Draft decision

The AER accepts a terrorism event, as proposed by ElectraNet, as a nominated pass through event.

The AER does not accept a natural disaster event or an insurance cap event as nominated pass through events in the forms proposed by ElectraNet. Before it can accept these events as nominated pass through events, the AER requires ElectraNet to amend its definitions of:

- a natural disaster event
- an insurance cap event

in accordance with section 16.5 of this draft decision.

16.2 ElectraNet's proposal

In response to the AEMC's rule change, ElectraNet has nominated three additional cost pass through events. It has also proposed a consequential change to its self insurance arrangements.

Proposed pass though events

The recent AEMC cost pass through rule change included transitional provisions allowing ElectraNet 30 days, or until 1 September 2012 to nominate additional pass through events as part of its revenue

859 NER, clauses 6A.7.3 and 11.49.4.
860 An insurance event is different to an insurance cap event. Discussed in section 16.4.3.
861 AEMC, *Rule determination, National electricity amendment (cost pass through arrangements for network service providers) rule 2012*, 2 August 2012.
862 NER, clause 6A.6.9.

proposal for the 2013–18 regulatory control period.[863] ElectraNet proposed the AER approve three additional pass through events:[864]

A terrorism event

> An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to ElectraNet of providing prescribed transmission services.[865]

A natural disaster event

> Any flood, fire, earthquake, or other natural disaster beyond the reasonable control of ElectraNet which *materially* increases the costs to ElectraNet of providing *prescribed transmission services*.

An insurance cap event

> Either:
>
> ElectraNet incurs a liability or liabilities; or
>
> an event occurs,
>
> where:
>
> the incurring of that liability or those liabilities or the occurrence of that event would, but for the existence of a relevant policy limit, entitle the provider (or another person on its behalf) to receive a payment, or a greater payment, under the insurance policy to which that limit applies; and
>
> the costs that are incurred or are likely to be incurred by the provider in respect of that liability or those liabilities or in respect of that event, and that would be covered by the insurance policy but for the relevant policy limit, are such as to materially increase the costs to ElectraNet of providing prescribed transmission services.
>
> For the purpose of this event, the relevant policy limit for an insurance policy means any limit on the maximum amount that can be claimed under that insurance policy, including a limit set on the maximum amount of a single claim or on the maximum amount of a number of claims over a certain period of time.

Proposed change to self insurance

ElectraNet lodged its revenue proposal before the AEMC rule change gave it the ability to nominate additional pass through events.[866] The forecast self insurance allowance in the revenue proposal included $0.7 million to self insure for bushfire liability above the commercial insurance cap. ElectraNet stated that if the AER accepted the proposed insurance cap event, this risk would no longer need to be self insured. Consequently ElectraNet would reduce the proposed self insurance allowance by $0.7 million, from $7.5 million to $6.8 million. The AER's assessment of ElectraNet's insurance and self insurance proposals is discussed in the opex attachment in section 5.4.3.

[863] AEMC, *Rule determination, National electricity amendment (cost pass through arrangements for network service providers) rule 2012*, 2 August 2012, p. 31.

[864] ElectraNet, *Pass through event proposal*, 29 August 2012.

[865] ElectraNet's proposed definition is the same as the definition previously included in the NER.

[866] AEMC, *Rule determination, National electricity amendment (cost pass through arrangements for network service providers) rule 2012*, 2 August 2012.

16.3 Assessment approach

In deciding whether to accept ElectraNet's proposed nominated pass through events, the AER must have regard to the nominated pass through event considerations, namely:[867]

1. whether the event is covered by another category of pass through event
2. whether the nature or type of event can be clearly identified
3. whether a prudent service provider could reasonably prevent an event of that nature from occurring or substantially mitigate the cost impact of such an event
4. whether the relevant service provider could insure against the event, having regard to:
   a. the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or
   b. whether the event can be self insured on the basis that:
      i. it is possible to calculate the self-insurance premium; and
      ii. the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services.

The AER assessed the pass through events nominated by ElectraNet against each of the considerations.

Also in its assessment, the AER had regard to the National Electricity Objective (NEO) and the revenue and pricing principles in the National Electricity Law (NEL). In particular, the AER weighed two key issues:

- the need for ElectraNet to be able to recover the efficient costs it incurs as a result of unexpected events outside of its control

against

- the need to preserve incentives for ElectraNet to efficiently manage the risks of such events through commercial and self insurance.

16.4 Reasons for draft decision

The AER accepts a terrorism event as a nominated pass through event as proposed by ElectraNet. However, the AER does not accept a natural disaster event or an insurance cap event as nominated pass through events as proposed by ElectraNet.

16.4.1 A terrorism event

The AER accepts ElectraNet's proposed definition of a terrorism event having had regard to the nominated event pass through considerations and because it is consistent with the previous NER definition of a terrorism event.

In August 2012, the AEMC rule change removed a terrorism event from the list of pass through events under the NER. The AEMC noted the change did not imply a terrorism event should not be

867 NER, clause 6A.6.9(b); NER, definition of '*nominated event pass through considerations'*, chapter 10.

treated as a pass through event. Rather, the change was made so the decision whether to accept a terrorism event would be made by the AER as part of the determination process, considering the circumstances of each network business.[868]

A terrorism event by its very nature is an unexpected event involving force or violence. The AER considers ElectraNet is limited in its ability to prevent or substantially mitigate the cost impact of such an event beyond the measures discussed in this section. Further, the AER is satisfied ElectraNet has taken prudential measures to reasonably prevent a terrorism event or to substantially lessen the cost impact where possible.[869] ElectraNet's pass through event proposal outlines these measures, which include:

- the meshed design of the network;
- the dual path overlaid telecommunication network (to support operational control and electrical system protection);
- holdings of critical common spares;
- ElectraNet's emergency deployment plans;
- perimeter security systems and video surveillance; and
- participation in the South Australian's government's emergency plans to enable the protection and restoration of essential services.[870]

ElectraNet has some commercial insurance for general property damage under its Industrial Special Risk Policy (for insured assets such as substations). This would be triggered by a terrorism act which falls under the *Terrorism Insurance Act 2003* and which is subject to a Ministerial declaration. ElectraNet stated that in relation to cyber terrorism, the insurance market is still developing, and obtaining insurance coverage remains difficult.[871] If a terrorism event occurred which was covered by general property insurance, the AER would consider any costs incurred net of insurance compensation.[872]

The AER considers it is not possible to calculate a self insurance premium for a terrorism event due to the potential magnitude and low probability of such an event. Further, the potential loss to ElectraNet would have a significant impact on its ability to provide network services.

16.4.2 Natural disaster event

The AER does not accept ElectraNet's proposed definition of a natural disaster event. Before it can accept ElectraNet's proposal, the AER requires ElectraNet to amend its definitions for the reasons set out here and in accordance with section 16.5.

Assessment of the event

In accepting a natural disaster event the AER must be satisfied ElectraNet has taken sufficient steps to avoid, mitigate and commercially insure against natural disasters. While ElectraNet is limited in its ability to prevent or substantially mitigate the cost impact of a natural disaster, the AER is satisfied ElectraNet has taken prudent preventative measures against potential natural disasters. ElectraNet's

868 AEMC, *Rule determination*, August 2012, p. 25.
869 NER, clause 6A.9.6(b); NER, definition of '*nominated event pass through considerations',* chapter 10.
870 ElectraNet, *Pass through event proposal*, p. 6.
871 ElectraNet, *Pass through event proposal*, p. 6.
872 NER, clause 6A.7.3(j)(2).

pass through event proposal outlines these measures, such as fire start management, flood assessment and seismic design standards.[873]

ElectraNet has commercial insurance that would cover some costs of specific natural disasters (such as earthquakes) up to a policy limit. In addition, it has elected to self insure for line failures arising from local storm damage (but noted such a localised event would be unlikely to be considered a natural disaster). The AER accepts that the potential severity of the cost of a natural disaster means ElectraNet cannot self insure for the full cost of such an event. Similarly, the AER has previously concluded that a natural disaster event satisfies the consideration that the pass through event cannot be self insured.[874] This is because a self insurance premium cannot be calculated, or the potential loss to the relevant business is catastrophic.

Assessment of ElectraNet's definition

ElectraNet's proposed definition of a natural disaster event is based on the pass through event that the AER approved for the Victorian DNSPs[875] and Aurora[876] but with modifications. The AER considers that some, but not all of these modifications are appropriate.

ElectraNet proposed removing the requirement that the natural disaster be 'major' as such an event will be major if it 'materially' increases the costs to ElectraNet.[877] The AER does not agree that the word major should be removed. The normal meaning of the term 'natural disaster' refers to a major (not a local) flood, fire or earthquake. Further, accepting an event which was not major would not be consistent with the pass through event considerations. For example, a TNSP can obtain insurance on reasonable commercial terms for damage caused by a flood, fire, earthquake or other natural disaster which is not major.

ElectraNet proposed that the natural disaster must be beyond the 'reasonable control of ElectraNet' rather than 'beyond the control of ElectraNet'. This is consistent with the third nominated pass through event consideration (section 16.3) which is whether a prudent service provider could *reasonably* prevent the event from occurring or substantially lessen the cost impact.[878] Therefore, the AER accepts the inclusion of the word 'reasonable' in the definition of a natural disaster event.

However, the AER does not accept ElectraNet's proposal to exclude from the definition of a natural disaster event any reference to the forecast operating expenditure in the AER’s determination. This is because the AER assesses the opex allowance in the determination is having regard to ElectraNet's insurance premium proposal and, as such, this must be taken into account by the AER in assessing the pass through application.

The AER notes that to the extent that a natural disaster event results in costs materially above the insured cap then ElectraNet can apply for an insurance cap pass through event.

The AER does not accept ElectraNet's proposal to remove the requirement that the natural disaster occur during the relevant regulatory control period.[879] Under the NER a nominated pass through event is available only for the determination for which it is proposed. In addition, the cost pass through

873 ElectraNet, *Pass through event proposal*, p. 9.
874 AER, *Victorian electricity DNSPs distribution determination 2011–15*, final decision, October 2010, p. 745; AER, *Aurora Energy distribution determination 2012–17*, draft decision, p. 285.
875 AER, *Victorian electricity DNSPs distribution determination 2011–15, draft decision*, June 2010. P.726-728; *Final decision*, October 2010, p. 746.
876 AER, *Aurora distribution determination 2012–17, draft decision*, p. 39.
877 NER definition of '*materially*' for the purposes of clause 6A.7.3, chapter 10.
878 NER, Chapter 10, definition of 'nominated pass through even considerations', paragraph (c).
879 ElectraNet, *Pass through event proposal*, p. 8.

provisions for TNSPs require a pass through application be made within 90 business days of an event occurring.[880] The AER also notes that the AEMC's rule change deals with events that occur in a previous regulatory control period, in circumstances where it is too late to include the costs associated with those events in a TNSP's total revenue cap for the subsequent regulatory control period. [881]

A natural disaster event allows ElectraNet to recover the capital costs of a natural disaster (such as damaged infrastructure). However, ElectraNet was concerned a substantial proportion of the costs associated with a natural disaster are likely to arise from third party liability claims, such as when a bushfire triggers a fire related liability claims. It stated such claims typically occur more than 90 business days after the occurrence of the natural disaster. The AER considers an insurance cap event (rather than a natural disaster event) more appropriately addresses such costs. The following section discusses how the definition of an insurance cap event addresses ElectraNet's concerns.

The AER requires that the definition of a natural disaster event be amended as follows:

> Any major fire, flood, earthquake, or other natural disaster beyond the reasonable control of ElectraNet that occurs during the 2013–18 regulatory control period and materially increases the costs to ElectraNet of providing *prescribed transmission services*.
>
> For the avoidance of doubt, in assessing a natural disaster event application, the AER will have regard to:
>
> - the insurance premium proposal submitted by ElectraNet in its revenue proposal
> - the forecast operating expenditure allowance approved in the AER's final decision; and
> - the reasons for that decision.

16.4.3 Insurance cap event

The AER does not accept ElectraNet's proposed definition of an insurance cap event. Before it can accept ElectraNet's proposal, the AER requires ElectraNet to amend its definition for the reasons set out here and in accordance with section 16.5.

Assessment of the event

An insurance cap event is not already covered by a NER defined pass through event. A NER defined insurance event (available to all TNSPs) is an event for which an insurance allowance is provided but:

- the cost of the insurance materially changes from the allowance, or
- the insurance becomes unavailable, or
- the business incurs a deductible (excess) and the cost is materially different to that allowed in the determination.

Whereas, the nominated insurance cap event allows a TNSP to pass through costs that exceed the maximum payout that the TNSP receives from its insurer when an insured risk eventuates.

The AER needs to be satisfied an insurance cap event represents the most efficient mechanism to address ElectraNet's insurance cap risks. It considers ElectraNet can optimise its risk management by

[880] NER, clause 6A.7.3(c).
[881] NER, clause 6A.7.3(j).

externally insuring to a certain level of risk. This approach however, has the potential to leave uninsured some losses that are above the insurance cap.

The AER can accept an insurance cap event only after it has considered the availability of commercial or self insurance. ElectraNet has commercial insurance to manage the risk of third party liability and property damage. But it stated the coverage of such insurance is typically capped at a level beyond which it is unable or uneconomic to insure.

The nominated pass through event considerations require the AER to consider whether an insurance cap event can be self-insured. The AER considers that any self insurance allowance (if it could be calculated) would be too high for consumers to pay or inadequate to compensate ElectraNet if such an event were to occur. Therefore, the AER considers that compensation should be deferred unless and until an insurance cap event occurs.[882]

In determining the pass through amount for a pass through application, the AER must consider the efficiency of ElectraNet's decisions and actions in relation to the event. Such consideration includes whether ElectraNet failed to take reasonable action to reduce the cost of the event. This gives ElectraNet an incentive to mitigate the likelihood of a pass through event occurring and the costs associated with the event. The AER will take into account:

- whether ElectraNet had an appropriate insurance policy to cover particular risks, and
- whether ElectraNet could reasonably prevent the event from occurring or substantially mitigate the cost impact of the event.

The AER considers that when assessing an insurance cap event pass through application, its enquiry will necessarily encompass any claims or findings of negligence.[883] Therefore, the AER has not excluded negligence from the definition of insurance cap event.

The AER further notes that unlawful conduct and gross negligence would not be covered by an insurer and that acts or omissions resulting from such unlawful conduct or gross negligence could not trigger this pass through event.

Assessment of ElectraNet's definition

The AER does not accept ElectraNet's proposed definition of an insurance cap event.

ElectraNet's definition of an insurance cap event is substantially different from the definitions used in the AER's determinations for the Victorian DNSPs and Aurora.

ElectraNet was concerned that liability claims typically occur well after the underlying event and after the 90 business day period within which a pass through application needs to be lodged under the NER. The AER's definition addresses this issue by defining the pass through event in terms of when ElectraNet claims on an insurance policy and not when the underlying event occurs. In addition, the

[882] Transend was of the view that ElectraNet's proposal to reduce its self insurance premiums is illustrative of the efficiency of not forcing customers to pay now for events with such a low probability of occurrence. Transend, *Submission on ElectraNet's pass through proposal*, September 2012, p. 3.

[883] Information concerning the circumstances of the event may include negligence as determined by a court of law. As part of its broad enquiry, the AER may also consider claims of negligence that have not been proved or made in a court of law. For example, there may be claims of negligence but no public admission of negligence, or a confidential settlement that prevents public disclosure. It is also possible that what constitutes negligence may not be settled. The NEL and NER do not limit the AER in taking such information into account. The AER will consider all such information available to it. Such information may or may not be determinative of whether the event was in the service provider's control for the purposes of the AER's decision on the pass through application.

relevant insurance policy is not limited to an insurance policy held during the 2013-18 regulatory control period; rather it also includes a policy purchased in a previous regulatory period. ElectraNet can thus make a cost pass through application for above cap costs associated with an event that occurred in a previous regulatory period.

The AER does not agree with the two triggers that ElectraNet proposed for an insurance cap event, namely "ElectraNet incurs a liability or liabilities" or "an event occurs", because neither trigger requires ElectraNet to make a claim on an insurance policy. The AER's definition clarifies that an insurance cap event can only occur once ElectraNet has made an insurance claim.

The AER does not accept ElectraNet's reference to the costs that are incurred or "are likely to be incurred". The drafting of the cost pass through mechanism presupposes the recovery of actual eligible costs not likely costs. For example, the materiality threshold is met if the actual, not the likely, costs incurred by the TNSP exceed 1 per cent of the maximum allowed revenue for that regulatory year.

The AER considers ElectraNet's definition of an insurance cap event does not link the relevant insurance policy with the insurance component of ElectraNet's forecast operating expenditure. ElectraNet would be expected to spend that component to obtain an efficient level of insurance, but the AER cannot compel ElectraNet to do so. There is a risk that customers pay twice—first through the operational expenditure allowance, and then through the cost pass through mechanism. ECCSA raised the same concern in its submission: “consumers would par the costs above the cap and allow the network provider to retain the benefit of the opex under-run”.[884] ElectraNet's proposed insurance cap definition does not address this risk.

In contrast, the AER’s definition highlights the fact that when the AER assesses an insurance cap event cost pass through application, it will have regard to the insurance premiums in ElectraNet’s revenue proposal and the forecast opex allowance approved in the AER’s final decision. This is consistent with the revenue and pricing principles and is in the long term interests of consumers.

The AER therefore requires ElectraNet to amend the definition of an insurance cap event be amended as follows:

An insurance cap event means an event whereby:

1. ElectraNet makes a claim and receives a payment under a relevant insurance policy;
2. ElectraNet incurs costs beyond the relevant policy limit; and
3. The costs beyond the relevant policy limit materially increase the costs to ElectraNet of providing prescribed transmission services.

   For the purposes of this insurance cap event:

4. The relevant policy limit is the greater of:
   a. ElectraNet’s actual policy limit at the time of the event that gives rise to the claim, and
   b. its policy limit at the time the AER made its final decision on ElectraNet’s transmission determination proposal for the period 2013-18.

884 ECCSA, *Submission on ElectraNet’s pass through proposal*, September 2012, p. 3.

5. For the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6A.7.3, the AER will have regard to:

    i. the insurance premium proposal submitted by ElectraNet in its revenue proposal.

    ii. the forecast operating expenditure allowance approved in the AER's final decision; and

    iii. the reasons for that decision.

6. A relevant insurance policy is an insurance policy held during the 2013-18 regulatory control period or a previous regulatory control period in which ElectraNet was regulated.[885]

Materiality Threshold

The materiality threshold for a pass through event is met if the costs incurred by the TNSP exceed 1 per cent of the maximum allowed revenue for that regulatory year.[886]

16.5 Revisions

Revision 16.1: the AER accepts the following nominated pass through events to apply to ElectraNet in the 2013–18 regulatory control period:

A terrorism event: an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to ElectraNet of providing prescribed transmission services.

A natural disaster event: Any major fire, flood, earthquake, or other natural disaster beyond the reasonable control of ElectraNet that occurs during the 2013–18 regulatory control period and materially increases the costs to ElectraNet of providing *prescribed transmission services*.

For the avoidance of doubt, in assessing a natural disaster event application, the AER will have regard to:

1. the insurance premium proposal submitted by ElectraNet in its revenue proposal

2. the forecast operating expenditure allowance approved in the AER's final decision, and

3. the reasons for that decision.

An insurance cap event: an event whereby:

1. ElectraNet makes a claim and receives a payment under a relevant insurance policy;

2. ElectraNet incurs costs beyond the relevant policy limit; and

[885] AER, *Draft decision, SP AusNet distribution determination 2011–15, insurance pass through event*, (by orders of the Australian Competition Tribunal) p. 2.

[886] NER, definition of 'materially', chapter 10.

3. The costs beyond the relevant policy limit materially increase the costs to ElectraNet of providing prescribed transmission services.

For the purposes of this insurance cap event:

4. The relevant policy limit is the greater of:

a. ElectraNet's actual policy limit at the time of the event that gives rise to the claim, and

b. its policy limit at the time the AER made its final decision on ElectraNet's transmission determination proposal for the period 2013-18.

5. For the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6A.7.3, the AER will have regard to:

i. the insurance premium proposal submitted by ElectraNet in its revenue proposal

ii. the forecast operating expenditure allowance approved in the AER's final decision; and

iii. the reasons for that decision.

6. A relevant insurance policy is an insurance policy held during the 2013-18 regulatory control period or a previous regulatory control period in which ElectraNet was regulated.

17 List of submissions

Submission	Date submitted
Clean Energy Council	27 August 2012
Energy Consumers Coalition of South Australia	20 August 2012
Energy Consumers Coalition of South Australia – submission on ElectraNet's cost pass through event proposal	11 September 2012
Energy Users Association of Australia	30 August 2012
South Australian Council of Social Services	17 August 2012
South Australian Government - Hon Tom Koutsantonis MP, Minister for Mineral Resources and Energy	5 October 2012
Transend – submission on ElectraNet's cost pass through event proposal	12 October 2012
TransGrid – submission on ElectraNet's cost pass through proposal	15 October 2012

Appendixes

A Opex analysis

The AER's draft decision on ElectraNet's opex proposal is set out in attachment 5. This appendix sets out further details of the AER's analysis of ElectraNet's opex that supports the AER's draft decision.

A.1 Efficiency of ElectraNet's historical expenditure

ElectraNet proposed its 2011–12 costs be used as the base reference year for forecasting its opex requirements for the next regulatory control period. The AER reviewed ElectraNet's operating expenditure during the current regulatory control period (2008-13) to understand whether this expenditure was efficient and appropriate for use as the reference base year expenditure. The AER considered the incentives faced by ElectraNet during the current regulatory control period, benchmarked ElectraNet's opex against other TNSPs in the NEM (see appendix B) and assessed its proposed, and alternative, base year expenditure.

A.1.1 Effect of incentives on current regulatory control period opex

The AER used ElectraNet’s historical controllable opex to assess firstly, the efficiency of ElectraNet’s proposed base year, and secondly whether its total forecast opex reasonably reflects the opex criteria. The AER also investigated the effect of the continuous incentive properties of a revenue cap control mechanism and the EBSS on recurrent base opex.

Under the chapter 6A NER incentive regime, TNSPs are subject to a revenue cap control mechanism and an EBSS. This regime is intended to provide them with continuous incentives to reduce their costs over a regulatory control period. The AER investigated the impact these incentives have had on ElectraNet’s historical opex, to satisfy itself the base opex is representative of recurrent costs. The AER made further adjustments to the base year for non-controllable exclusions for the purposes of the EBSS carryover. The EBSS adjustments are discussed in section 6.

Table A.1 compares ElectraNet’s controllable actual opex with the allowance set by the AER for the 2008–13 regulatory control period. It shows ElectraNet expects to exceed its total allowance by about $1.1 million, but that the most significant overspend occurred in 2011–12 when ElectraNet spent $68.1 million, $6.0 million more than its allowance. This data, of itself, does not indicate whether ElectraNet's opex in the 2008–13 regulatory control period is efficient so the AER has undertaken further analysis to help it assess ElectraNet's base opex.

Table A.1 AER allowance and ElectraNet's actual/estimated controllable opex, 2008–13 ($ million, 2012-13)

Year	AER allowance	ElectraNet actual/estimated	Difference
2008–09	55.6	53.8	1.8
2009–10	57.4	55.1	2.3
2010–11	59.3	58.4	0.9
2011–12*	62.1	68.1	-6.0
2012–13	63.6	65.3	-1.7
Total	297.9	299.0	-1.1

*Actual from regulatory accounts (submitted 31 October 2012).
Source: ENET100 and 2011–12 regulatory accounts.

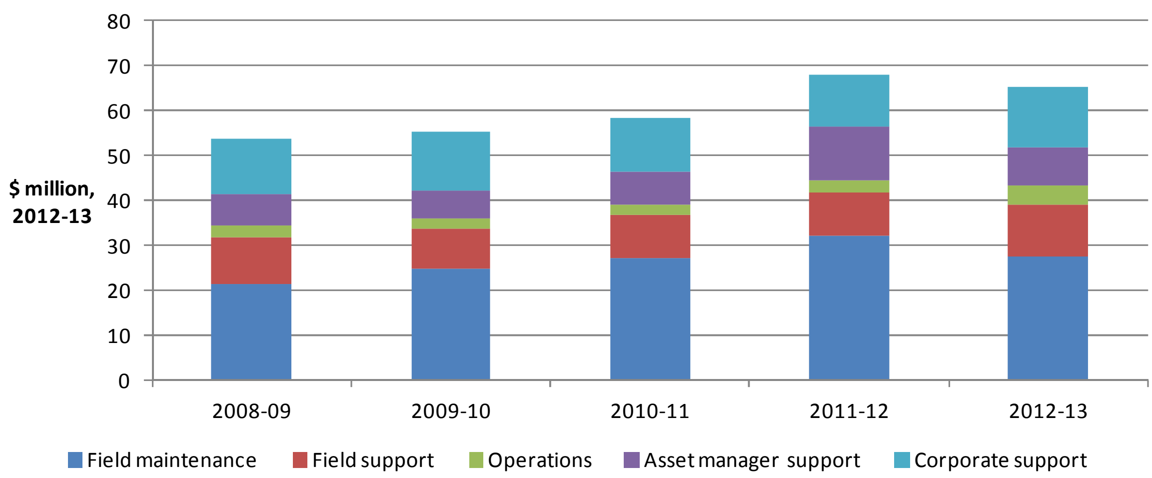
A.1.2 Choice of base year for assessment approach

Figure A.1 shows ElectraNet's historical controllable opex by category for the 2008–13 regulatory control period. All categories of expenditure over the 2008–13 regulatory control period exhibit an upward trend and the field maintenance and operations categories have the most notable increases during period.

ElectraNet proposed 2011–12 as its base year from which to generate the component of its forecast that was base-year-extrapolated. The AER does not accept that the fourth year, 2011–12, is efficient or reflective of recurrent costs. All expenditure categories increased in the fourth year compared with previous years, and compared with the regulatory allowance. The overall opex subsequently decreased in the fifth year (2012-13).

In contrast, the actual expenditure in third year, 2010–11 is closer to the average of the regulatory control period, of the first three years and closer to the regulatory allowance in all opex categories. The AER considers the third year, 2010–11 is a year that better reflects recurrent and efficient costs.

Figure A.1 ElectraNet's controllable opex by category ($ million, 2012-13)



Source: ENET 100 (includes 2011–12 regulatory account actual expenditure submitted 31/10/12).

Non-recurrent costs and other adjustments to the base year

The AER removed non-recurrent costs from base year opex because these costs are not considered reflective of the level of future recurrent requirements. These were:

- Movement in provisions—total provisions of $388,000[887] (nominal) were removed from the base year. The AER assumed all provisions are associated with internal labour only.

- Land tax costs—the AER's substitute forecast treated land tax was as a zero-based cost. The amount of $1.145 million (nominal) was removed from the base-year in the field support category. This estimate was based on the 2011–12 land tax[888] (converted to 2010–11 prices). The AER then assessed the land-tax costs using the land-tax formula, which accounted for the tax rate by land type and forecast land holdings in the 2013–18 regulatory control period. The AER's assessment for land tax was less than ElectraNet's for the reasons set out in section 5.4.3.

- Additional reset costs—the AER observed that ElectraNet had two types of reset costs in the 2008–13 regulatory control period:

  - Firstly, ElectraNet has an ongoing base-level requirement for each year of $0.6 million (2010–11). This cost is included in the 2010–11 base year expenditure, so the AER is not required to adjust the base year costs for this ongoing recurrent expenditure.

  - Secondly, ElectraNet's actual/estimated expenditure for the final two years of the 2008–13 regulatory control period significantly stepped up, by $1.4 million (2012-13). Although ElectraNet did not apply for a 'step change' of $1.4 million for years four and five in the 2013–18 regulatory control period (that is, 2016-17 and 2018-19) in its proposal the AER adjusted its forecast to allow for these additional reset costs. The AER considered that ElectraNet may not have requested these additional reset costs because it assumed the fourth year as its base year, and therefore this step increase was implied.

A.2 Step changes

Step changes allow for additional funding when a new requirement or change in circumstance requires the service provider to undertake expenditure that was not accounted for in the base year level of opex. Examples of step changes include new safety regulations requiring ongoing additional opex, and opex related to a new capital project or other new legislative requirements. In assessing ElectraNet's proposed step changes,[889] the AER considered whether they are consistent with the expenditure that a prudent service provider would incur when acting efficiently, in accordance with the opex criteria. If the AER considers these step changes meet this requirement, then the total forecast opex includes an incremental increase in base year opex.

Routine maintenance

The AER accepts ElectraNet's proposed routine maintenance forecast of $80.9 million because ElectraNet presented evidence of having thoroughly considered routine maintenance requirements.[890] The AER generally supports the integrated asset management framework that ElectraNet has begun to deploy, because such a regime can facilitate lifecycle management of risks in a transparent and

[887] ElectraNet, ENET 239.
[888] ElectraNet, *Revenue proposal*, p. 109.
[889] ElectraNet proposed field maintenance activities (routine maintenance, corrective maintenance and operational refurbishment) and network optimisation as a 'bottom-up' forecast of opex requirements. This is equivalent to requesting a step/scope change adjustment to the AER's historical trend amount for each of these category in the AER's top-down methodology.
[890] EMCa, *ElectraNet technical review*, 30 October 2012, p. 139.

cost effective manner. ElectraNet presented evidence of its continuous improvement program resulting in innovation and efficiency improvements of five per cent in the routine maintenance program.[891]

Accommodation

ElectraNet proposed a step change increase in office accommodation requirement of $2.1 million for 2013–18 regulatory control period. ElectraNet proposed the office accommodation should be leased rather than purchased (it is therefore opex, not capex). Usually the AER would include office accommodation as a base year recurrent expenditure item, which would then be escalated for network growth and economies of scale to provide for future organisational growth requirements. But in this case, the AER accepts that the additional leasing arrangements constitute a step change in ElectraNet's opex requirement because ElectraNet did not have any leasing opex costs in 2010–11 (the base year).[892] That said, the AER is not satisfied that the total of the proposed accommodation costs reflect the opex criteria or meet the opex objectives because it considers ElectraNet has over-estimated its requirements.

ElectraNet entered a lease agreement in 2011–12 and the AER used this actual revealed cost as the basis for forecasting the recurrent accommodation costs for the 2013–18 regulatory control period. The AER considers this actual cost likely to be an efficient cost for forecasting opex accommodation requirements because ElectraNet committed to the lease in the current regulatory control period, even though it received no allowance for this expenditure category. The AER therefore added a step-change to the base year to reflect ElectraNet's new office accommodation requirements. This step change was based on an estimated annual lease cost of $170,128 in 2010–11 (nominal). The impact of this base year adjustment is an increase in ElectraNet's allowance of about $1.0 million over the 2013–18 regulatory control period.

ElectraNet proposed an additional accommodation step change of $1.5 million for additional accommodation requirements commencing in 2014-15. The AER does not accept this second step change because future organisational growth requirements are captured by the network growth factors and the economies of scale factors applied to the base year (which was increased to include office accommodation).[893]

Transmission license fee

The AER also applied step change decrements. In accordance with the South Australian Electricity Act 1996, the Minister for Mineral Resources and Energy announced his intention to reduce the annual transmission fee licence by 32 per cent for the 2013–18 regulatory control period.[894] The AER reduced ElectraNet's proposed opex forecast by $4.9 million accordingly.[895]

Step changes not accepted

ElectraNet also proposed step changes that the AER does not accept.

891 EMCa, *ElectraNet technical review*, 30 October 2012, p. 139.
892 ElectraNet had a small amount of about $6,000
893 That is, the base year which includes the AER's first step change for office accommodation
894 The Honourable Tom Koutsantonis MP, Member for West Torrens, *Submission to AER*, 27 September 2012
895 This is the total savings across the 2013–18 regulatory control period based on a reduction of $800,000 in the base year 2010–11 and estimated as a reduction of $800,000 per annum for five years, escalated.

Corrective maintenance

The AER does not accept increased corrective maintenance costs as a step change to its top-down forecast.[896] ElectraNet proposed $68.8 million for corrective maintenance. It presented costs in two forms: a backlog of already identified defects and a base level of defects. The AER found ElectraNet's proposed corrective maintenance expenditure does not meet the opex criteria[897] because it over estimated incoming defect rates. The AER used the revealed costs for corrective maintenance ($43.7 million) in its substitute forecast.

Operational refurbishment

ElectraNet proposed an 80 per cent increase in its operational refurbishment expenditure (up to $64.9 million), as well as a new capex category of refurbishment that includes about $50 million. The AER does not accept the proposed increase to operational refurbishment over the historical trend amount (the differential being $18.1 million). The inputs that determine ElectraNet's operational refurbishment forecast are based on historical high risk defect rates that are upwardly biased, so the operational refurbishment forecasts are overestimated. The AER used the revealed costs for corrective maintenance in its substitute forecast.

Network optimisation

ElectraNet proposed a $13.3 million step change for a new category of opex called network optimisation. The AER does not accept ElectraNet's proposed network optimisation expenditure as a step change in the AER's top–down opex forecast, for the following reasons.

ElectraNet identified network optimisation opex as a one-off cost that applies to only the 2013–18 regulatory control period and that is expected to defer capital augmentation, but it did not demonstrate the economic case for the costs or benefits. The AER asked ElectraNet to provide evidence of the $13.3 million capex–opex trade-off and to identify the capital deferrals and costs of these projects.[898] In response, ElectraNet provided a single example of the Bungama–Hummocks 132 kV line, for which it proposed the benefit is the deferral by seven to nine years of $191 million of capex augmentation, from an upfront opex cost of $650 000. While this deferral is a good example, ElectraNet did not quantify the net present value of the remaining $12.65 million of the forecast network optimisation opex, show the timing of the remainder of the deferrals, or identify how these deferrals link to the capex program and forecast.[899]

According to ElectraNet, the purpose of the network optimisation expenditure is 'to improve the capability of the transmission network in relation to power flows, asset utilisation and asset management'.[900] This type of expenditure is not a step change for new circumstances.[901] Rather, the AER's revealed costs (top down) forecast provides for the expenditure as business-as-usual expenditure in an efficient base year. The TNSP's proposed network optimisation is part of a core

896 ElectraNet proposed corrective maintenance and operational refurbishment as a bottom up forecast. This is equivalent to a step-change adjustment to the AER's historical trend amount for each of these categories.

897 NER, clauses 6A.6.(c)(1)–(2)

898 ElectraNet, ENET245 response to AER RP 24 AER12/5741.

899 ElectraNet's ENET245 included another five examples of substation works, with a combined total cost of $1.62 million, but did not quantify the benefits (such as capex deferrals) for these projects.

900 ElectraNet, *Revenue proposal 2013–18*, 31 May 2012, p. 89.

901 ElectraNet treated this as a zero based forecast for a new category.

business objective that is a business-as-usual practice for any efficiently operated business. It is not driven by an exogenous factor or business restructure.[902]

ElectraNet proposed the network optimisation expenditure as a step change[903] because it considers the projects are driven by 'the advent of technological advancements now available to the business on a cost effective basis'.[904] The AER disagrees that the availability of technology and engineering innovation necessarily constitutes a step change to a business's operating environment. The decision to deploy technology is within the control of a business. Technological, engineering and computing advancements occur continually, and any business should consider the technological/innovation efficiency frontier options (in all functional areas of its business) as part of its efficient business-as-usual practices.

The NER framework incentivises programs of work that aim to increase the use of existing infrastructure. In fact, the AER recently proposed changes to the Service Target Performance Incentive Scheme (STPIS)[905] that incentivise this type of program through a network capability component. However, if ElectraNet were to demonstrate the network optimisation projects have an overall positive net present value, then its opex allowance should not include the $13.3 million expenditure because the program will effectively fund itself over time. Importantly, ElectraNet is not precluded from spending its opex allowance on this program and recovering the benefits over time through the efficiency benefit scharing scheme (EBSS) and STPIS.

In its submission on ElectraNet's proposal, the Energy Users Association of Australia (EUAA) was sceptical about the need for network optimisation as an opex category.[906] The Energy Consumers Coalition of South Australia (ECCSA) submitted that ElectraNet's proposed network optimisation opex category is not an imposed requirement but is a new element designed to provide a network that should either reduce costs (future opex and capex) and/or increase availability.[907] While the ECCSA supports such actions, it queried why they have not been a consistent part of the ElectraNet activities as to a reasonable degree they have the same focus as the STPIS which has been in operation for a considerable period.[908] ECCSA also commented that ElectraNet needs to quantify the benefit that this added program will achieve so that the added cost can be offset against benefits before the AER should include the additional cost.[909]

Superannuation liability

ElectraNet proposed a step change of $2.4 million to cover the shortfall in its defined benefit plan superannuation contribution. The AER does not accept this proposed step change. To the extent that any superannuation costs were lower (higher) than average in the base year, ElectraNet will be rewarded (penalised) through its EBSS incentive mechanism. In other words, ElectraNet will retain any cost reductions (increases) in the base year for a five year period. To adjust the base year would lead to over (under) compensation.

902 The AER's top–down forecasting approach provides for an efficient opex allowance for field maintenance, network operations, asset management and network support activities.
903 ElectraNet proposed this category as an opex category that has been zero based (using a bottom–up forecast approach).
904 ElectraNet, *Revenue proposal*, p. 99.
905 AER, Draft electricity TNSP STPIS, September 2012, p. 13.
906 Energy Users Association of Australia, *Submission on ElectraNet revenue proposal - Revised* - 30 August 2012, p. 14.
907 Energy Consumers Coalition of South Australia, *Submission on ElectraNet revenue proposal,* 20 August 2012, p, 38.
908 Energy Consumers Coalition of South Australia, Submission on ElectraNet revenue proposal, 20 August 2012, p, 38.
909 Energy Consumers Coalition of South Australia, Submission on ElectraNet revenue proposal, 20 August 2012, p, 38.

B Benchmarking

The AER has undertaken benchmarking for informative purposes. The AER, in assessing ElectraNet's proposed expenditure against the capex and opex criteria, must have regard to the capex and opex factors.[910] One such factor is the benchmark capex and opex that would be incurred by an efficient TNSP.[911] Benchmarking provides an indication of the relative performance of a TNSP against its peers, but it does have limitations. Limitations include:[912]

- differences between purchases and leasing policies
- variations in the network characteristics of TNSPs including the age, size and maturity of their networks and the markets they serve
- different capitalisation, cost allocation and other accounting policies.

B.1 Assessment approach

ElectraNet submitted its forecast opex to RAB ratio for 2013-14 compared with that of other TNSPs. It showed that ElectraNet's opex over RAB is 3.8 per cent which is the second largest ratio of the five TNSPs (Transend's ratio was 4.5 per cent). However, the AER notes the ratio of opex over RAB for one given year is a limited metric for comparative purposes. A small opex to RAB ratio may indicate low operating expenditure, or it may indicate a large RAB.

The AER compared ElectraNet's historical expenditures against other TNSPs in the NEM using ratio analysis. In considering benchmark expenditure, there are two key factors the AER can adjust for: density and size. Density is important as for example more opex is typically required for less dense networks, partly due to increased travel costs. Size is also important because larger TNSPs will benefit from economies of scale. The AER used load density (megawatts per kilometre of line, MW/km) to normalise the results and it considers load density the appropriate measure given that the size in TNSPs differs substantially.

Rather than using a single year (ElectraNet's method), the AER used the five year average for each metric (from 2006-07 to 2010–11) as the basis for comparison because this provides a less volatile comparison (the five year average reduces the likelihood of any single year affecting the results).

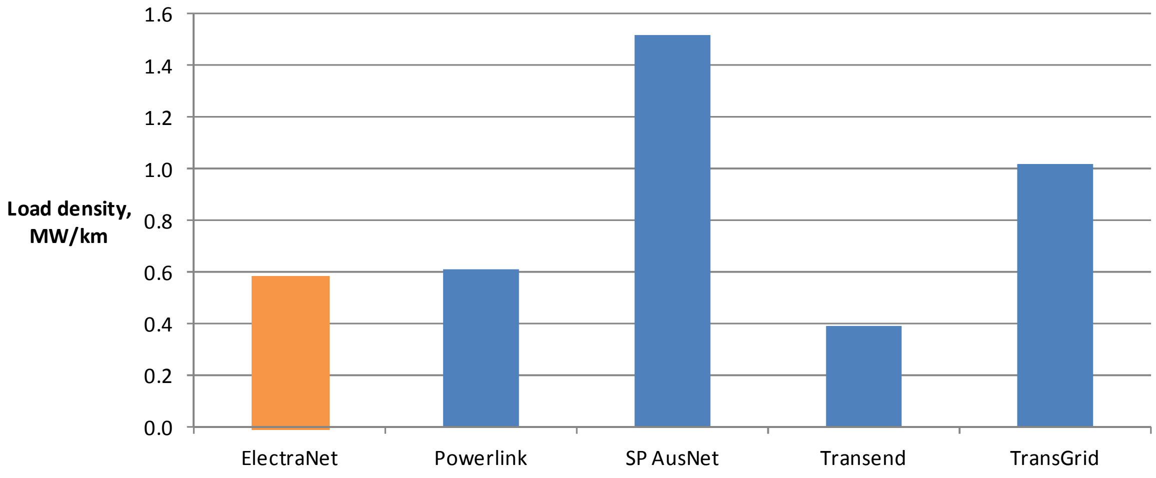
The opex numbers in this analysis include grid support (network support) for ElectraNet, Powerlink, Transend and TransGrid. When reviewing and comparing total expenditure between TNSPs, grid support should be included in the analysis because it reflects the capex/opex trade-off. However, when focus of the analysis is on opex (alone), it is helpful to exclude grid support from the analysis for comparative purposes of controllable opex.

[910] NER, clauses 6A.6.7(e) and 6A.6.6(e).
[911] NER, clauses 6A.6.7(e)(4) and 6A.6.6(e)(4).
[912] AER, *Draft decision, Victorian electricity distribution network service providers: Distribution determination 2011–15*, Appendix I, pp. 78–79.

B.2 Comparison of network characteristics

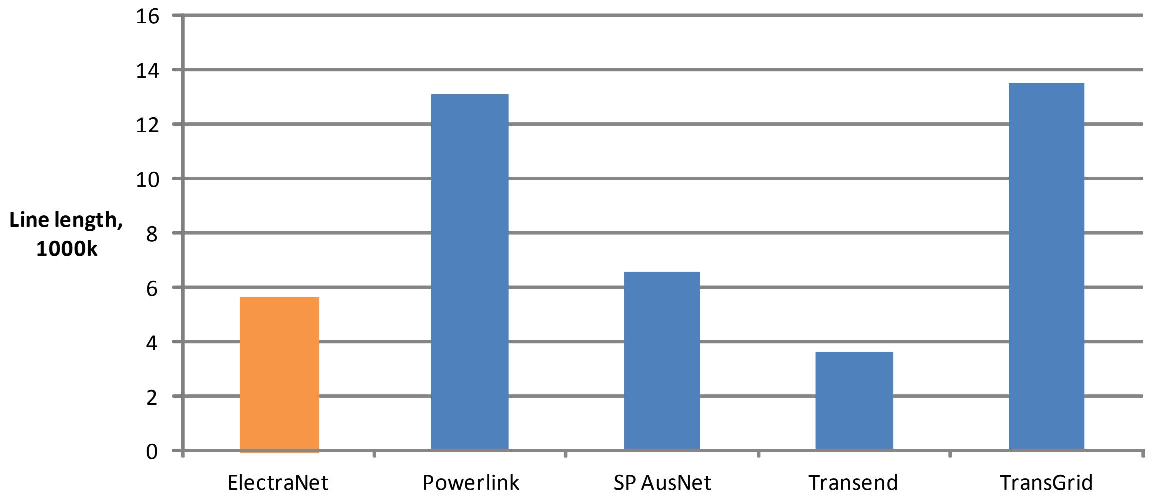
This section first sets out ElectraNet's network characteristics relative to the other TNSPs in the NEM, based on the average of the five years from 2006–07 to 2010–11. Figures B.1 to figure B.4 respectively show: average load density, average line length, peak demand and electricity distributed. ElectraNet is in the middle of the range in each of these measures, that is, it is neither the highest nor the lowest of the five TNSPs.

Figure B.1 Average load density (MW/km)



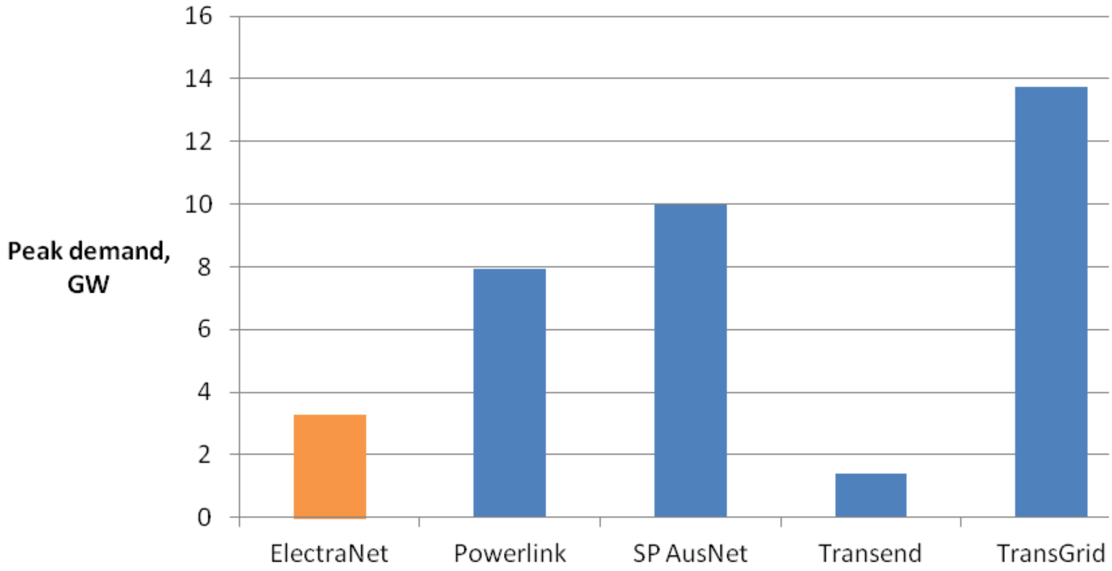
Source: AER, *TNSP performance report 2010–11*; AER analysis.

Figure B.2 Average line length (1000km)



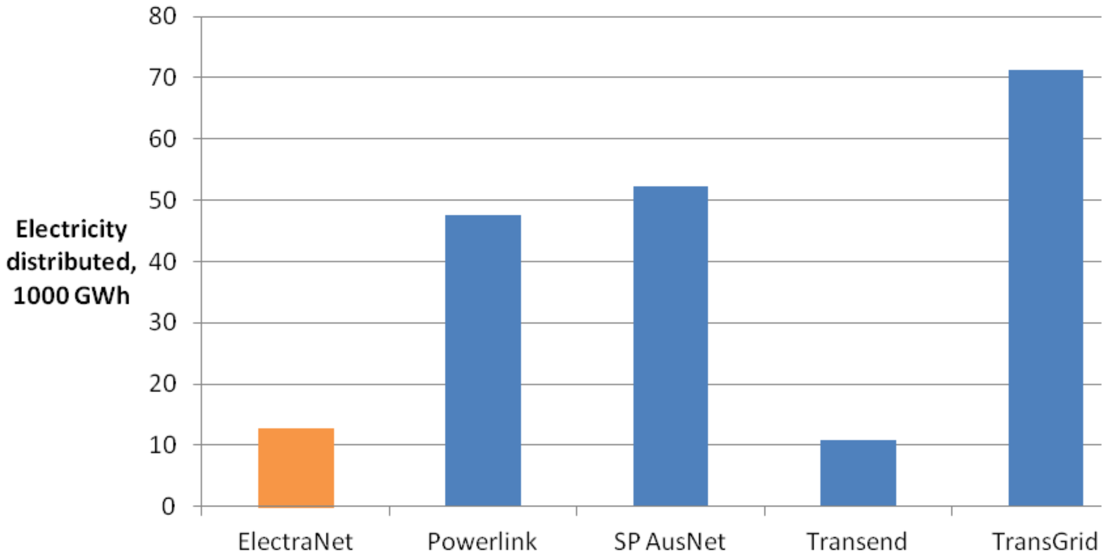
Source: AER, *TNSP performance report 2010–11*; AER analysis.

Figure B.3 Peak demand (GW)



Source: AER, *TNSP performance report 2010–11*; AER analysis.

Figure B.4 Electricity distributed (1000GW)

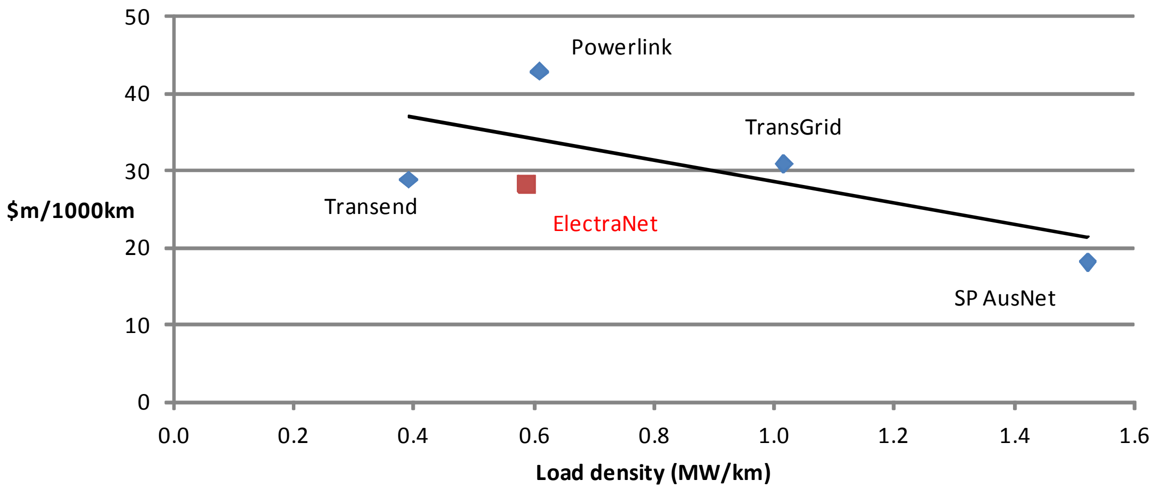


Source: AER, *TNSP performance report 2010–11*; AER analysis.

B.2.1 Capex benchmarking

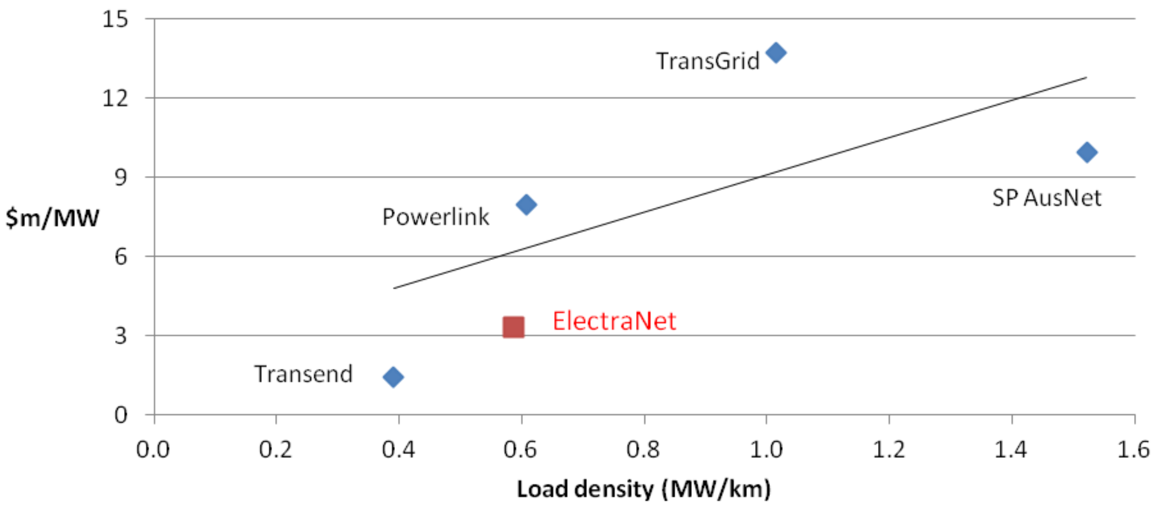
The AER undertook a ratio analysis to compare the level of recent historical capex for ElectraNet against other TNSPs in the NEM (see figure B.5 to figure B.7). The analysis below suggests ElectraNet's incurred capex is relatively lower when compared to other TNSPs. The AER notes that the figures below only reflect actual capex incurred and therefore do not include capex for either the 2011–12 or 2012–13 years. ElectraNet's capex is higher in these years than its previous historical average. The trend line in the figures below relates to all TNSPs.

Figure B.5 Capex/line length ($ million, 2012–13/1000km)



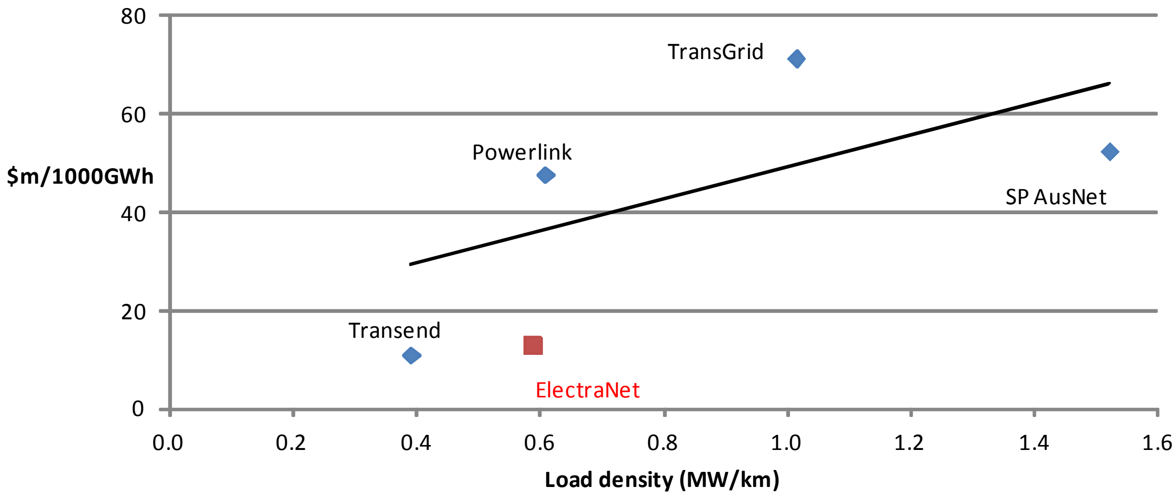
Source: AER, *TNSP performance report 2010–11*; AER analysis.

Figure B.6 Capex/peak demand ($ million, 2012–13/MW)



Source: AER, *TNSP performance report 2010–11*; AER analysis.

Figure B.7 Capex/electricity distributed ($ million, 2012–13/1000GWh)

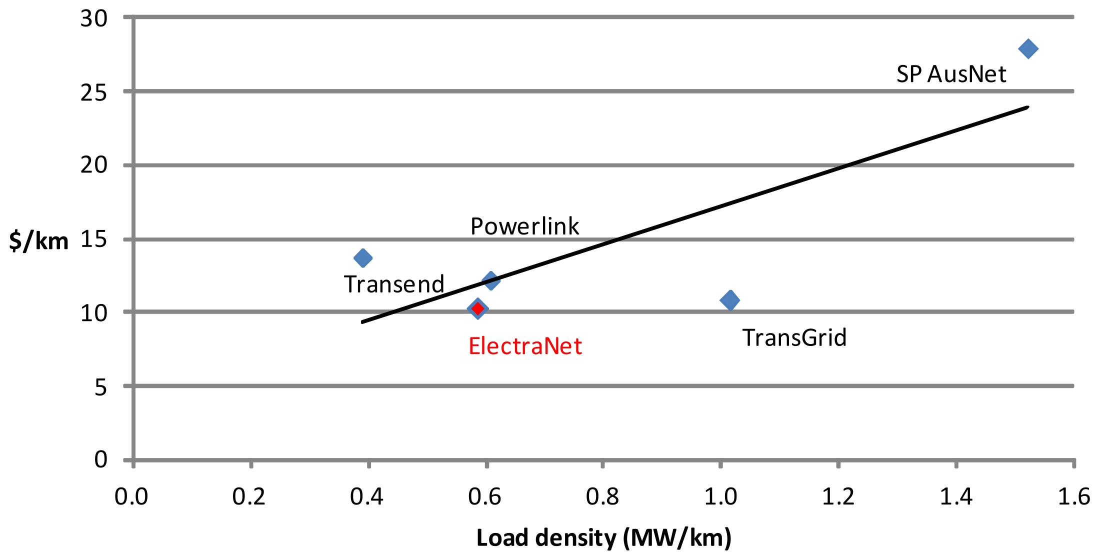


Source: AER, *TNSP performance report 2010–11*; AER analysis.

B.2.2 Opex benchmarking

Figure B.8 to Figure B.10 show the opex/line length, opex/peak demand and opex/electricity distributed.[913] The trend line in the figures below relates to all TNSPs. A key feature of these charts is that ElectraNet's opex per unit of electricity distributed is the highest in the NEM when compared with the average for all TNSPs, shown in figure B.10. Importantly, this is based on the five year average to 2010–11 but ElectraNet's proposal shows it had a large increase in its actual opex spend in 2011–12 and in its estimated opex spend in 2012-13 (both years' expenditure is above the regulatory allowance). Therefore, assuming no change in the other TNSP's expenditure profile, ElectraNet's opex to electricity distributed ratio is likely to be even higher in more recent years.

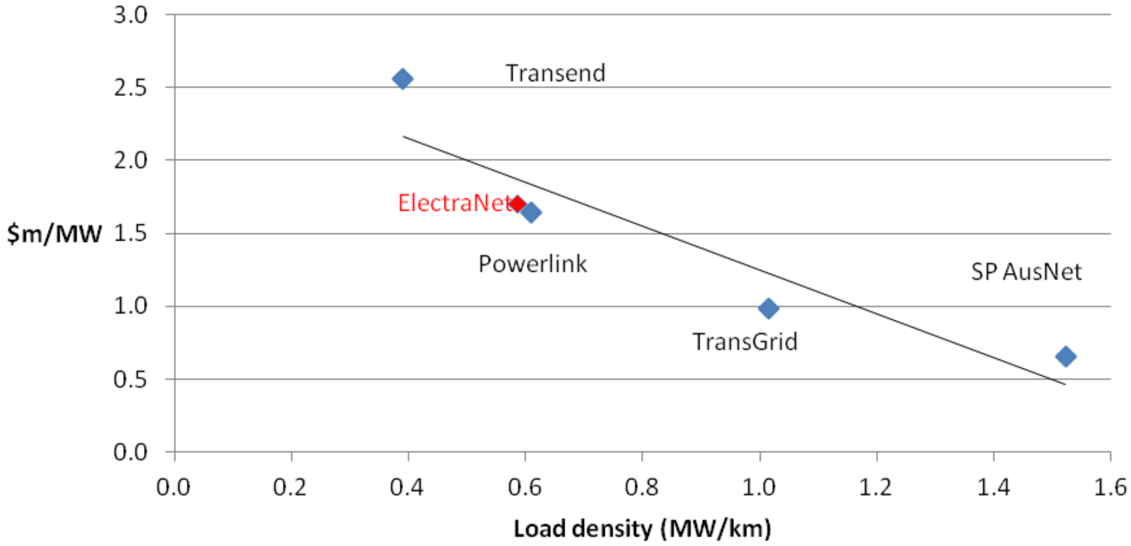
Figure B.8 Opex/line length ($ million, 2012–13/1000km)



Source: AER, *TNSP performance report 2010–11*; AER analysis.

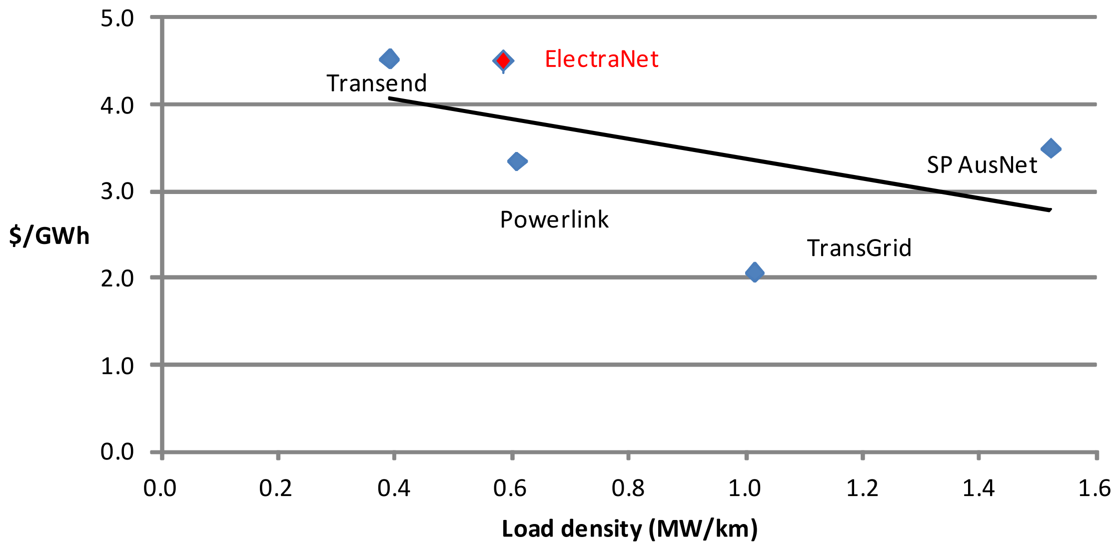
913 Opex includes grid support (network support).

Figure B.9 Opex/peak demand ($ million, 2012–13/MW)



Source: AER, *TNSP performance report 2010–11*; AER analysis.

Figure B.10 Opex/electricity distributed ($ million, 2012–13/1000GWh)



Source: AER, *TNSP performance report 2010–11*; AER analysis.

C Contingent project appendix

Table C.1 Contingent projects rejected by the AER—Trigger event is demand increase within the demand forecast

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)
2	Lower Eyre Peninsula Reinforcement	1. Demand forecast at Port Lincoln exceeding 49 MW 2. Successful completion of the RIT-T showing transmission investment is justified	588
6	Yorke Peninsula Reinforcement	1. Aggregate demand forecast for the Hummocks, Kadina East, Ardrossan West and Dalrymple connection points exceeding 90 MW 2. Successful completion of the RIT-T showing a new connection point in the region is justified	191

Source: ElectraNet, *Revenue proposal*, pp. 79–81.

Table C.2 Contingent projects rejected by the AER—Trigger event is DNSP request for new connection point but demand increase is within the demand forecast

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)
5	Fleurieu Peninsula Reinforcement	1. Formal request for a new regulated connection point from the DNSP 2. Successful completion of the Regulatory Test demonstrating a transmission solution is economically justified	210
12	Western Suburbs Reinforcement	1. Formal request for a new regulated connection point from the DNSP 2. Successful completion of the RIT-T showing a new or modified connection point in the region is justified	20
14	Northern Suburbs Reinforcement	1. Formal request for a new regulated connection point from the DNSP OR Formal request to modify an existing connection point from the DNSP 2. Successful completion of the RIT-T showing a new or modified connection point in the region is justified	48
17	Port Pirie System Reinforcement	1. Formal request for a new regulated connection point from the DNSP 2. Successful completion of the RIT-T showing a new connection point in the region is justified	36

Source: ElectraNet, *Revenue proposal*, pp. 79–81.

Table C.3 Contingent projects rejected by the AER—Trigger event is above the demand forecast and not substantiated

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)
13	Southern Suburbs Reinforcement	1. An increase in demand exceeding the forecast load published in the 2011 APR for 2018-19 by 60 MW for the aggregate of the Southern Suburbs connection points 2. Successful completion of the RIT-T showing that modifying the existing connection points is justified	171
18	South East Connection Point Reinforcement	1. Formal request for a new regulated connection point from the DNSP 2. Successful application of the RIT-T showing a new or modified connection point in the region is justified	25
19	South East Region Augmentation	1. An increase in the forecast demand exceeding the forecast published in the 2011 APR for 2018-19 by 4 MW at Keith, 3 MW at Kincraig or 3 MW at Penola West connection points 2. Successful application of the RIT-T showing a new or modified connection point is justified	28
20	Lower South East Region Transformer Reinforcement	1. An increase in the forecast demand exceeding the forecast published in the 2011 APR for 2018-19 by 25 MW for the aggregate of the Snuggery, Blanche and Mount Gambier connection points 2. Successful application of the RIT-T showing a new or modified connection point is justified	19

Source: ElectraNet, *Revenue proposal*, pp. 79–81.

Table C.4 Contingent projects rejected by the AER—projects driven by the Olympic Dam expansion

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)
3	Upper Eyre Peninsula Reinforcement	1. Customer commitment to connect increasing the total forecast demand supplied from Cultana to above 590 MW 2. Successful completion of the RIT-T showing network development is justified	113
9	Northern Transmission Reinforcement - Load	1. Customer commitment to connect increasing the total forecast demand supplied from Davenport to above 260 MW 2. Successful completion of the RIT-T showing network development in the region is justified	247

Source: ElectraNet, *Revenue proposal*, pp. 79–81.

Table C.5 Market benefits projects rejected by the AER

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)
7	Para - Brinkworth/Bungama Davenport 275 kV Transmission Upgrade	1. Successful completion of the RIT-T demonstrating positive net market benefits	50
11	Upper South East Generation Expansion	1. Successful completion of the RIT-T demonstrating positive net market benefits	48
15	Torrens Island Switchyard Development	1. Successful completion of the RIT-T demonstrating positive net market benefits	54

Source: ElectraNet, *Revenue proposal*, pp. 79–81.

Table C.6 Contingent projects rejected by the AER—not feasible

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)
1	Eyre Peninsula Connection Point	1. Customer commitment to connect OR an increase of 5 MW in load forecast above the forecast published in the 2011 APR for 2018-19 on the transmission network south of Cultana 2. Successful completion of the RIT-T showing a new connection point in the region is justified	33

Source: ElectraNet, *Revenue proposal*, pp. 79–81.

Table C.7 **Contingent projects for which the AER requires revised trigger events**

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (2012–13)	Indicative revised trigger event (as appropriate)
4	Riverland Reinforcement	1. An increase of 12.5 MW in load forecast above the forecast published in the 2011 APR for 2018-19 for the North West Bend and Berri connection points OR publication by AEMO of available Murraylink dispatch into South Australia that is insufficient to provide the necessary network support to meet ETC reliability standards in the Riverland region. 2. Successful completion of the RIT-T showing transmission investment is justified.	407	1.a Total forecast demand exceeds 110 MW in the Riverland for the North West Bend and Berri connection points (ElectraNet to identify the underlying driver of this demand increase). or 1.b Publication by AEMO of available Murraylink dispatch into South Australia that is insufficient to provide support to the Riverland causing thermal limitations in the Robertstown to Berri transmission lines, causing a breach of the ETC. 2. Successful completion of the RIT-T demonstrating that reinforcement of the Riverland is justified. 3. ElectraNet Board commitment to proceed with the project subject to AER approval of the contingent project. 4. Completion of a comprehensive assessment of all alternatives to the contingent project solution.
8	South East to Heywood Interconnection Upgrade	1. Successful completion of the RIT-T demonstrating positive net market benefits	96	1. Successful completion of the RIT-T demonstrating positive net market benefits. 2. ElectraNet Board commitment to proceed with the project subject to AER approval of the contingent project. 3. Determination by the AER under clause 5.6.6AA that the proposed investment satisfies the RIT-T.[914]
10	Davenport Reactive Support	1. Commitment to the retirement of the Playford Power Station 2. Successful completion of the RIT-T showing installation of additional reactive support at Davenport is justified	42	1. Commitment to the retirement of the Playford Power Station. 2. Successful completion of the RIT-T showing installation of additional reactive support at Davenport is justified 3. ElectraNet Board commitment to proceed with the project subject to AER approval of the contingent

914 The AER understands that under the new version of the NER, this clause will be reflected at clause 5.16.6

				project. 4. The completion of a comprehensive assessment of all alternatives to the contingent project solution.
16	Mid North Connection Point	1. Formal request for a new regulated connection point from the DNSP 2. Successful completion of the RIT-T showing a new connection point in the region is justified	59	1. Addition of a step load to the distribution system, in the upper north east of the mid-north region, that increases the total load on the Jamestown to Peterborough 33 kV subtransmission line to exceed 13.3 MVA and causing thermal and voltage limitations in the distribution network. 2. ElectraNet Board commitment to proceed with the project subject to AER approval of the contingent project. 3. Completion of the RIT-T demonstrating that a new connection point in the upper north east of the mid-north region is justified 4. Formal request for a new connection point in the upper north-east of the mid-north region 5. The completion of a comprehensive assessment of all alternatives to the contingent project solution.
21	Upper North Region Line Reinforcement	1. Customer commitment to connect and/or an increase in forecast demand of 10 MW above the forecast published in the 2011 APR for 2018-19 at a distance of more than 10 km from Davenport 2. Successful application of the RIT-T showing a new connection point and line upgrade is justified	62	1. Customer commitment to connect to the transmission network along the Davenport - Pimba transmission line. 2. Customer connection increases demand serviced on this transmission line to exceed 76 MW causing thermal limitations on the network. 3. Successful completion of the RIT-T demonstrating that reinforcement of the transmission line is justified. 4. ElectraNet Board commitment to proceed with the project subject to AER approval of the contingent project. 5. The completion of a comprehensive assessment of all alternatives to the contingent project solution.

Source: ElectraNet, *Revenue proposal*, pp. 79–81; AER analysis