Final decision

ElectraNet

Transmission determination

2013–14 to 2017–18

April 2013

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

Part 1 – AER's final decision

1 About the review

The Australian Energy Regulator (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 we operate. 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. We must make a transmission determination for ElectraNet every five years to determine how much revenue ElectraNet can recover from its customers. This final decision contains the reasons for our transmission determination that will apply to ElectraNet during the 2013–18 regulatory control period.

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), generators and direct connect customers.[1]

Figure 1.1 ElectraNet's electricity transmission network

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

[1] ElectraNet's direct connect customers include large industrial customers and mines. These are customers who are directly connected to ElectraNet's transmission network.

1.1 AER final decision

The AER does not approve ElectraNet's revised revenue proposal for the 2013–18 regulatory control period. We determined ElectraNet will recover revenue of $1577.5 million ($nominal) over the 2013–18 regulatory control period. We approve ElectraNet's proposed five year regulatory control period commencing 1 July 2013.

We made our final decision in accordance with the relevant sections of the NEL and NER. For instance, we considered whether ElectraNet's forecast capital expenditure (capex) and operating expenditure (opex) reflect the efficient costs that a prudent operator requires to meet the NER objectives (set out in section 2.3).[2] In forming our views on whether ElectraNet's capex and opex forecasts are efficient and prudent, we took account of the factors listed in the NER.[3]

In reaching our final decision, we:

- analysed ElectraNet's revenue proposal, revised revenue proposal and supporting information
- considered submissions from interested parties
- considered views expressed at public forums and other stakeholder engagement meetings
- considered advice and analysis provided by AER commissioned experts.

1.2 National Electricity Law and National Electricity Rules requirements

The NEL contains two overarching principles that we must apply when performing our economic regulatory functions. Under section 16(1)(a) of the NEL we 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.

We must also take into account the revenue and pricing principles when making a transmission determination.[4] These principles require a TNSP to be provided with an opportunity to recover at least its efficient costs, and incentives to promote economic efficiency.

In assessing ElectraNet's revenue proposal, we reviewed ElectraNet's business and governance practices, including its asset management and maintenance strategies. To inform our final decision, we sought to understand how ElectraNet operates and manages its transmission network.

1.3 Review process

Our review process comprises several stages. These stages include considering the TNSP's revenue proposal and revised revenue proposal, submissions from interested parties on both proposals and our draft decision, and making the final decision and transmission determination. We engaged with ElectraNet and other stakeholders during this process. Submissions and expert advice received during the review process are available on the AER website at www.aer.gov.au/node/16617.

2 NER, clauses 6A.6.6(c) and 6A.6.7(c).
3 NER, clauses 6A.6.6(e) and 6A.6.7(e).
4 NEL, clause 16(2)(a)(i). The revenue and pricing principles are set out in section 7A of the NEL.

Table 1.1 Key dates in the AER's decision making process

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

1.3.1 Submission of revised revenue proposal and the AER's final decision

ElectraNet submitted its revised revenue proposal and pricing methodology in relation to prescribed transmission services on 16 January 2013. It also submitted its revised negotiating framework for its negotiated services.

We commissioned the following independent consultants for our final decision:

- 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.
- Deloitte Access Economics for advice on forecast growth in labour costs.
- AM Actuaries for advice on cost pass throughs.

After considering submissions on our draft decision and the revised revenue proposal we must make a final decision and transmission determination.[5] The final decision must set out the analysis and reasons for our transmission determination. We must publish the final decision and transmission determination at least two months before the relevant regulatory control period begins.[6]

1.3.2 Public consultation

Effective consultation with stakeholders is essential to the performance of our regulatory functions. Throughout the review process we have actively engaged with stakeholders by:

- considering submissions made on ElectraNet's revenue proposals and our draft decision. We received 17 submissions during the review process from:
    - Clean Energy Council

5 NER, clauses 6A.13.3 and 6A.13.4.
6 NER, clause 6A.13.3.

    - Centrex Metals
    - Energy Users Association of Australia
    - Eyre Peninsula Local Government Association
    - Iron Road Limited
    - South Australian Council of Social Services
    - Energy Consumers Coalition of South Australia
    - The South Australian Minsister for Mineral Resources and Energy
    - The South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy
    - Transend (the Tasmanian TNSP)
    - TransGrid (the New South Wales TNSP).
- hosting a public forum in Adelaide on 23 July 2012 for stakeholders to engage with ElectraNet on its revenue proposal. This allowed stakeholders to put questions to both the AER and ElectraNet on the revenue proposal.
- having ElectraNet present its revenue proposals to the AER Chairman and Board members in June 2012 and February 2013. ElectraNet explained its proposals to the AER Chairman and Board members and responded to questions.
- engaging with EMCa and ElectraNet in an eight day on–site review of ElectraNet's revenue proposal in June and July 2012. The AER and EMCa directly engaged with ElectraNet staff involved in developing and managing the network and tested material and information that underpins the revenue proposals.
- engaging in ongoing discussions with ElectraNet about the revenue proposals. During this process, the AER and EMCa considered over 350 responses to information requested from ElectraNet.
- holding a workshop with ElectraNet in September 2012 where we outlined the findings of our technical consultant and a further workshop between the AER, EMCa and ElectraNet to allow for clarification of technical information that had a bearing on our findings.
- liaising with other stakeholders including:
    - the Australian Energy Market Operator (AEMO). We discussed ElectraNet's demand forecasts and matters relevant to reconciling regional demand forecast with connection point forecast.
    - the Essential Services Commission of South Australia (ESCOSA). We discussed the Electricity Transmission Code and the implications of the Code for ElectraNet's capex program.[7]

[7] The Electricty Transmission Code establishes the standards of service which ElectraNet must meet in providing transmission services in South Australia. Avaialable at www.escosa.sa.gov.au.

  - SA Power Networks to understand their demand forecasting approach. We also discussed how ElectraNet uses SA Power Network's connection point demand forecasts to inform its capex program.[8] We further discussed the process that SA Power Networks and ElectraNet engage in to arrive at mutually agreed demand forecasts.

  - SA Water to discuss the grandfathering arrangements under the NER in relation to replacing assets associated with SA Water's pumping stations and the service levels required by SA Water in the future.

  - the South Australian Department of Planning, Transport and Infrastructure. We discussed the effect of planning instruments on ElectraNet's easements and the possibility of residential encroachment upon those easements.

- hosting a predetermination conference in Adelaide on 12 December 2012 for stakeholders to engage with the AER and ElectraNet on our draft decision. This provided user groups and other stakeholders with an opportunity to ask questions about our draft decision. The Energy Users Association of Australia (EUAA) accepted our invitation and made a presentation at this conference.

The AER's review team had extensive direct engagement with ElectraNet throughout the review process. Appendix C sets out the key meetings during the assessment process between the AER staff and key stakeholders including ElectraNet.

1.3.3 Protected information submitted to the AER

We are committed to treating protected information received from TNSPs and other stakeholders in accordance with the NEL. The NEL allows us to disclose protected information under certain circumstances.[9]

1.3.4 Structure of decision document

This final decision is set out as follows:

- Part 1: AER's final decision – the final decision on ElectraNet's revenue proposal and a summary of our reasons

- Part 2: attachments – a detailed analysis of the components of the final decision

- Part 3: appendixes – list of contingent projects and trigger events and list of submissions received and stakeholder engagement meetings .

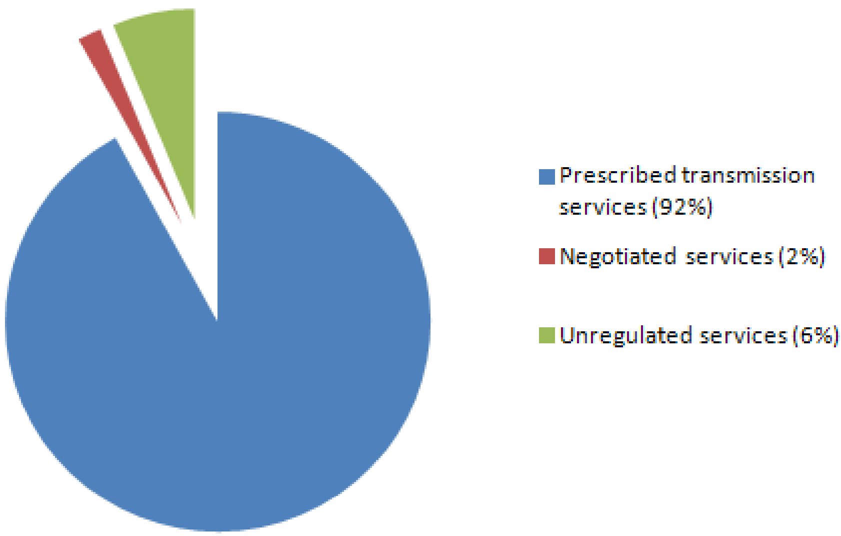
8 NER, clause 11.6.11.
9 NEL, part 3, division 6.

2 AER's approach

2.1 ElectraNet's electricity transmission services

ElectraNet's services (prescribed transmission services, negotiated services and unregulated services) relate to developing, operating and maintaining the South Australian electricity transmission network. Figure 2.1 shows ElectraNet derives the bulk of its revenue from providing prescribed transmission services. Our final decision mostly concerns our assessment of the cost to ElectraNet of providing these services.

Figure 2.1 ElectraNet's categories of service by revenue ($ 2010–11)



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

We regulate ElectraNet's prescribed transmission services under a revenue cap which sets the maximum allowed revenue (MAR) that ElectraNet can recover each year through its network tariffs. This revenue recovers the economic cost of providing prescribed transmission services to customers. ElectraNet's prescribed transmission services comprise:[10]

- 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 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 services include the maintenance of power system security and assisting in the planning of the power system (prescribed common transmission services).

10 ElectraNet, *Revenue proposal*, p. 12.

Unlike prescribed transmission services, we do not regulate the revenue that ElectraNet can earn from negotiated transmission services. The NER sets out the types of services classified as negotiated transmission services.[11] The NER requires us to make a determination on ElectraNet's negotiating framework and Negotiated Transmission Service Criteria (NTSC).[12] These two instruments facilitate the agreement between ElectraNet and the customer of the terms and conditions for the provision of negotiated transmission services. Attachment 12 provides detailed reasons for our final decision on ElectraNet's negotiated transmission services.

Unregulated services provided by ElectraNet are outside our jurisdiction and are not part of our final decision.

2.2 Maximum allowed revenue

ElectraNet recovers revenue from its customers via its network tariffs. Its pricing methodology, discussed in attachment 12, prescribes the way it recovers this revenue. To determine ElectraNet's revenue for the 2013–18 regulatory control period, we assess the total revenue required by ElectraNet to provide prescribed transmission services for each year of the period. This annual revenue requirement reflects the efficient costs of providing prescribed transmission services across the South Australian electricity transmission network.

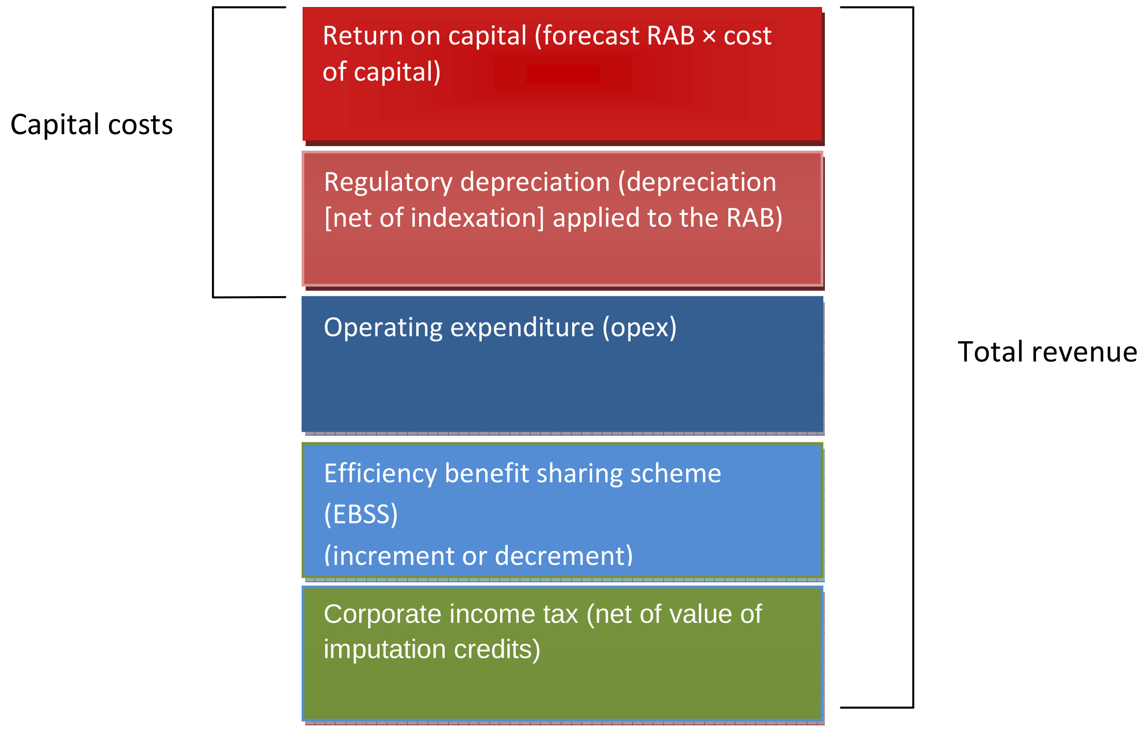
In accordance with the NER, we use the building block approach to determine the annual revenue requirement. That revenue requirement is determined by estimating the efficient costs that ElectraNet is likely to incur in providing prescribed transmission services. The underlying cost elements include:[13]

- 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.

Our assessment of capex directly affects the size of the regulatory asset base and therefore the return on capital and return of capital building blocks.

11 NER, chapter 10, glossary.
12 NER, clauses 6A.2.2(2) and (3).
13 NER, clause 6A.5.4(a).

Figure 2.2 The building block approach for determining total revenue



2.3 NER objectives of capex and opex forecasts

The NER sets out the following objectives for ElectraNet's forecasts of total capex and opex:[14]

- meeting expected demand
- complying with all applicable regulatory obligations or requirements
- maintaining the quality, reliability and security of supply
- maintaining the reliability, safety and security of the transmission system.

We must determine whether ElectraNet's forecast capex and opex reflect the efficient costs required to meet these objectives, based on a realistic expectation of the demand for transmission services and cost inputs.[15]

We consider ElectraNet is generally a well governed and efficient TNSP and its forecast expenditure is targeted at achieving the capex and opex objectives. Nevertheless, we are 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. For this reason, we determined substitute opex and capex forecasts.[16]

[14] NER, clauses 6A.6.6(a) and 6A.6.7(a).
[15] NER, clauses 6A.6.6(c) and 6A.6.7(c).
[16] NER, clauses 5A.6.6(f) and 6A.6.7(f).

3 Total revenue requirements and the impact on price

ElectraNet's total revenue is our forecast of the efficient costs of providing prescribed transmission services. The total revenue cap set out in this final decision has been determined by assessing the elements of ElectraNet's revised 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 final decision on average electricity prices for consumers.

3.1 Final decision

Our final decision on ElectraNet's total revenue cap (smoothed revenue) over the 2013–18 regulatory control period is $1577.5 million ($nominal). This is $31.3 million less than ElectraNet proposed in its revised revenue proposal. The key element of our final decision that reduced ElectraNet's proposed revenue is the opex allowance. Table 3.1 shows our final decision on ElectraNet's building blocks and total revenue. Each building block is discussed in detail in the attachments to this final decision.

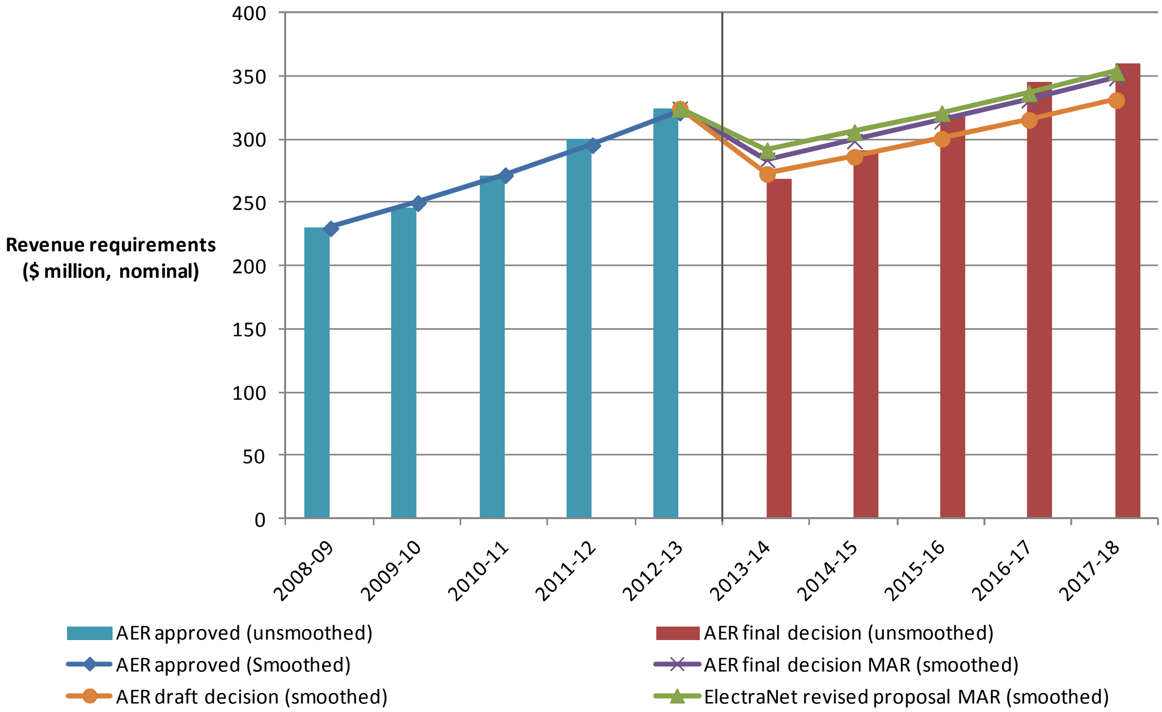
Table 3.1 AER final decision on ElectraNet's proposed revenue requirements ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Return on capital	155.2	169.5	178.2	187.8	194.7	885.3
Regulatory depreciation[a]	27.1	32.8	45.4	54.0	54.1	213.4
Operating expenditure	81.8	87.0	90.8	96.9	100.0	456.5
Efficiency benefit sharing scheme (carryover amounts)	–1.3	–3.6	– 1.4	0.0	4.8	–1.5
Net tax allowance	5.2	5.6	6.0	6.6	5.9	29.3
Annual building block revenue requirement (unsmoothed)	268.1	291.3	319.0	345.2	359.4	1583.0
Annual expected MAR (smoothed)	284.0	298.9	314.7	331.2	348.7	1577.5[b]
X factor (%)	n/a[c]	–2.69	–2.69	–2.69	–2.69	n/a

Source: AER analysis.
(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (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 final decision. The MAR for 2013–14 is around 14.6 per cent lower than the MAR in the final year of the 2008–13 regulatory control period (2012–13) in real dollar terms, or 12.5 per cent lower in nominal dollar terms.

Figure 3.1 compares ElectraNet's revised revenue proposal, our draft decision and our final decision for revenues over the 2013–18 regulatory control period with the revenue we approved for the 2008–13 regulatory control period. ElectraNet's proposed total smoothed revenue for the 2013–18 regulatory control period as set out in its revised revenue proposal is 17.5 per cent higher than the allowed total smoothed revenue for the 2008–13 regulatory control period (in nominal dollar terms). Our final decision smoothed revenue for the 2013–18 regulatory control period is 15.2 per cent higher than that approved for the 2008–13 regulatory control period (in nominal dollar terms).

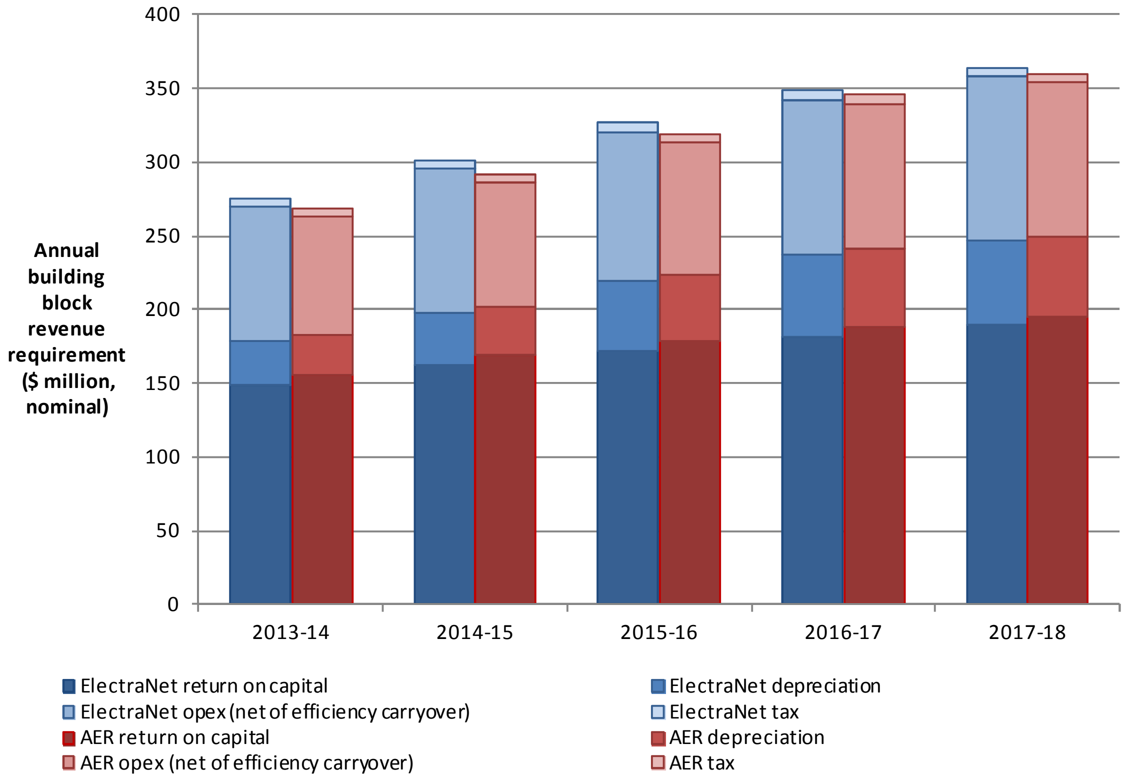
Figure 3.1 AER's final decision compared to AER's draft decision, ElectraNet's revised proposal revenue requirement and approved revenue for 2008–18 ($ million, nominal)



Source: ElectraNet, *Revised PTRM*, ENET316, 16 January 2013; AER, *PTRM for ElectraNet for the 2008–13 regulatory control period (including contingent projects)*, 11 February 2011; AER analysis.

Figure 3.2 shows the effect of our final decision adjustments on ElectraNet's proposed building blocks. This figure shows that our final decision will reduce ElectraNet's revised proposals for the regulatory depreciation and opex building blocks.

Figure 3.2 AER's final decision and ElectraNet's revised proposal annual building block revenue requirement (unsmoothed) ($ million, nominal)



Source: AER analysis.

1.1 Sensitivity analysis

We assessed the impact of key aspects of our final decision on ElectraNet's proposed revenue in its revised proposal. These include our final decision on forecast opex, forecast capex and the cost of capital. Our final decision on each is:

- capex of $690.7 million ($2012–13), compared with ElectraNet's proposed $750.1 million ($2012–13) in its revised proposal;[17] a reduction of 7.9 per cent.
- opex (net of EBSS carryover) of $416.1 million ($2012–13), compared with ElectraNet's proposed $465.4 million ($2012–13) in its revised proposal;[18] a reduction of 10.7 per cent.
- a cost of capital of 7.50 per cent, compared with ElectraNet's proposed 7.11 per cent in its revised proposal.

Table 3.2 shows that total unsmoothed revenue, based on our final decision on forecast capex, is $7.9 million ($nominal) or 0.5 per cent lower than ElectraNet's proposed total unsmoothed revenue in its revised proposal. It also shows that total unsmoothed revenue is $53.2 million ($nominal) or 3.3 per cent lower than ElectraNet's proposed total unsmoothed revenue in its revised proposal, when our final decision on forecast opex is adopted. In addition, the total unsmoothed revenue would be $49.3 million ($nominal) or 3.1 per cent higher than ElectraNet's proposed total unsmoothed revenue in its revised proposal when our final decision on the cost of capital is adopted.

17 Excludes equity raising costs.
18 Net of EBSS carryover amounts.

Table 3.2 Changes to ElectraNet's total proposed unsmoothed revenue, when AER's final decision capex forecast, opex forecast and WACC are adopted

	ElectraNet's revised proposal ($ million, 2012–13)	AER's final decision ($ million, 2012–13)	Revenue change ($ million, nominal)	Revenue change (per cent)
Capex[a]	750.1	690.7	–7.9	–0.5
Opex[b]	465.4	416.1	–53.2	–3.3
WACC	7.11%	7.50%	49.3	3.1

Source: ElectraNet, *Revised revenue proposal*, pp. 126 and 148–150; AER analysis.
(a) Excludes equity raising costs.
(b) Includes EBSS carryover amounts.

1.2 Indicative average impact on electricity prices

We have calculated an indicative effect of our final decision on the average South Australian residential customer's electricity bill. To calculate this, we have:

- 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),[19] and
- divided it by the forecast annual energy delivered in South Australia.[20]

Based on this approach, we estimate that our final decision will result in a slight increase of 0.8 per cent per annum ($nominal) in average transmission charges from 2012–13 to 2017–18.

We estimate that the final decision will result in slightly lower transmission charges on average over the 2013–18 regulatory control period compared with ElectraNet and Murraylink's revised proposals. ESCOSA estimates that transmission charges represent approximately 8 per cent on average of a typical customer's electricity bill in South Australia.[21] If the transmission charges based on our final decision are to pass through to end customers, a typical residential bill could be expected to increase by up to $4 in total ($nominal) during the 2013–18 regulatory control period.[22] In comparison, ElectraNet's and Murraylink's revised proposals would result in an average residential bill increase of approximately $6 in total. Similarly, if the transmission charges arising from this final decision are to pass through to end customers, a typical non-residential bill could be expected to increase by up to $7 in total ($nominal) during the 2013–18 regulatory control period.[23] In comparison, ElectraNet's and Murraylink's revised proposals would result in an average non-residential bill increase of approximately $11 in total.

19 Murraylink, *Pricing methodology v02*, January 2013, p. 3.
20 AEMO, *National electricity forecasting report*, 2012, table 6-1, Medium (Scenario 3, planning).
21 ESCOSA, *Email response to information request to the AER*, Enquiry regarding average electricity bills, 17 October 2012.
22 Based on an average South Australian residential electricity customer bill of $1800 ($nominal, excluding GST) in 2012–13, which reflect 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.
23 Based on an average South Australian non-residential customer bill of $3457 ($nominal, excluding GST) in 2012–13, which reflect 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.

2 Regulatory asset base

The regulatory asset base (RAB) is the value of ElectraNet's assets that are used to provide prescribed transmission services. These include 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 its RAB. Hence, the RAB is an important input for the return on capital and depreciation building blocks and, consequently, the revenue requirement.

As part of this final decision, we are required to assess ElectraNet's proposed opening value for the RAB for each year of the 2008–13 and 2013–18 regulatory control periods.[24] This involves:

- rolling forward the opening RAB as at 1 July 2008 to determine the closing RAB as at 30 June 2013[25]
- using our final 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.

Attachment 5 sets out the detailed reasons for our final decision on ElectraNet's RAB.

2.1 Final decision

We do not accept ElectraNet's revised opening RAB value as at 1 July 2013 and its forecast RAB for the 2013–18 regulatory control period. Table 2.1 and Table 2.2 set out our final decisions on the roll forward of ElectraNet's RAB during the 2008–13 regulatory control period and the forecast RAB for the 2013–18 regulatory control period respectively.

2.2 Summary of analysis and reasons

We determine ElectraNet's opening RAB value as at 1 July 2013 to be $2069.5 million. This value is $17.8 million (0.9 per cent) lower than ElectraNet's value of $2087.3 million in its revised revenue proposal because we made the following changes to the roll forward of the RAB:

- consistent with our draft decision, we adjusted the actual capex values rolled into the RAB to reverse the movements in capitalised provisions. We consider capitalised provisions should not be included in the RAB until ElectraNet has paid out (incurred) the expenses to which the provisions relate
- we updated the inflation input for 2012–13 using the actual March 2013 consumer price index.

We forecast ElectraNet's RAB to be $2620.3 million by 30 June 2018. This forecast represents a reduction of $70.6 million (2.6 per cent) to ElectraNet's revised revenue proposal. The main reasons for this reduction are our adjustments to:

- forecast capex (attachment 2)
- the opening RAB as at 1 July 2013 (attachment 5).

[24] NER, clause 6A.6.1.

[25] 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.

Table 2.1 AER's final decision on ElectraNet's RAB roll forward for the 2008–13 regulatory control period ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13[a]
Opening RAB	1311.8	1390.6	1493.6	1723.9	1866.4
Capital expenditure[b]	101.5	122.8	243.9	181.9	236.5
CPI indexation on opening RAB	32.4	40.2	49.8	27.3	46.7
Straight-line depreciation[c]	–55.0	–60.0	–63.3	–66.7	–73.3
Closing RAB as at 30 June	1390.6	1493.6	1723.9	1866.4	2076.3
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					–2.4
Opening RAB as at 1 July 2013					2069.5

(a) Based on estimated capex. An update for actual capex will be made at the next reset.
(b) As incurred, net of disposals, and adjusted for actual CPI and weighted average cost of capital (WACC).
(c) Adjusted for actual CPI. Based on as-commissioned capex.
Source: AER analysis.

Table 2.2 AER's final decision on ElectraNet's forecast RAB for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18
Opening RAB	2069.5	2259.8	2376.7	2503.9	2596.1
Capital expenditure[a]	217.4	149.7	172.5	146.2	78.3
Inflation indexation on opening RAB	51.7	56.5	59.4	62.6	64.9
Straight-line depreciation[b]	–78.9	–89.3	–104.8	–116.5	–119.0
Closing RAB	2259.8	2376.7	2503.9	2596.1	2620.3

(a) As incurred forecast, and net of disposals. In accordance with the timing assumptions of the post tax revenue model (PTRM), the forecast capex includes a half-WACC allowance to compensate for the six months before capex is added to the RAB for revenue modelling purposes.
(b) Based on forecast of as-commissioned capex.
Source: AER analysis.

3 Return on capital

As part of making a determination on the annual building block revenue requirement for a TNSP, we are required to make a decision on the return on capital building block.[26] The return on capital building block is calculated as the product of the weighted average cost of capital (or rate of return) and the value of the RAB.

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.[27]

Detailed reasons for our decision on the rate of return are provided in attachment 4.

3.1 Final decision

We accept ElectraNet's proposed method for estimating the weighted average cost of capital (WACC). Consistent with this method, we have updated ElectraNet's revised proposal WACC to reflect the agreed averaging period.[28] This results in a WACC of 7.50 per cent.

Our final decision on WACC only differs from ElectraNet's revised revenue proposal due to the use of different averaging periods for estimating the risk free rate and the debt risk premium (DRP). Specifically, ElectraNet's revised WACC was based on market data from September–October 2012. Our final decision, however, is based on market data from the agreed averaging period (February–March 2013). We agreed to the averaging period proposed by ElectraNet in June 2012. For this reason, we consider a 7.50 per cent rate of return provides ElectraNet with a reasonable opportunity to recover at least the efficient costs of capital financing. Consequently, we expect 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.

26 NER, clause 6A.5.4(a)(2).

27 NER, clause 6A.6.2(b).

28 ElectraNet's approved averaging period is the 20 days (on which indicative mid rates are published by the Reserve Bank of Australia) commencing on 18 February 2013.

Table 3.1 AER final decision on WACC parameters

Parameter	AER draft decision	ElectraNet revised proposal	AER final decision
Nominal risk free rate	3.51%	3.51%	3.51%
Equity beta	0.8	0.8	0.8
Market risk premium	6.50%	6.50%	6.50%
Debt risk premium	3.18%	3.18%	3.18%
Gearing level	60%	60%	60%
Inflation forecast	2.5%	2.5%	2.5%
Nominal post tax cost of equity	8.71%	8.71%	8.71%
Nominal pre tax cost of debt	6.69%	6.69%	6.69%
Nominal vanilla WACC	7.50%	7.50%	7.50%

Note: Our draft decision, and ElectraNet's revised proposal parameters have been updated to reflect the final averaging period, based on the respective methodologies. The parameters published in our draft decision and revised proposal were calculated on an indicative averaging period from September–October 2012. Our final decision reflects data from February–March 2013.

Source: AER analysis; ElectraNet, *Revised revenue proposal*, p. 126.

3.2 Summary of analysis and reasons

We did not change our assessment approach for individual parameters from our draft decision. Section 6.3 of attachment 6 of our draft decision details that approach.

Consistent with the NER, in estimating the rate of return we must use the values and credit rating determined in the WACC review.[29] ElectraNet's proposed method for determining the WACC adopted the values and credit rating determined in the WACC review, specifically:

- the equity beta
- the MRP
- the level of gearing
- the value of the assumed utilisation of imputation credits (gamma).[30]

We therefore accept ElectraNet's proposed values for these parameters.

In establishing the WACC, we also accept ElectraNet's proposed method for determining the DRP, the nominal risk free rate and inflation forecasts. Consistent with this method, we have updated ElectraNet's revised proposal WACC to reflect the agreed averaging period. Our reasons for accepting these methods are consistent with those adopted in our draft decision.

29 NER, clause 6A.6.2(h)

30 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.

4 Regulatory depreciation

We are required to decide on ElectraNet's indexation of the RAB and depreciation building blocks over the 2013–18 regulatory control period.[31] We use regulatory depreciation to model the nominal asset values over the regulatory control period, and set the depreciation allowance in the annual building block revenue requirement. The regulatory depreciation allowance (or return of capital) is the net total of the straight-line depreciation (negative) amount and the amount from indexation of the RAB (positive).

ElectraNet is required to submit a proposed depreciation schedule for its RAB in its revised proposal.[32] The depreciation schedule sets out the basis on which the RAB is to be depreciated for the purpose of determining the regulatory depreciation allowance. We must assess whether the revised depreciation schedule complies with the relevant requirements of the NER.[33]

Attachment 6 sets out the detailed reasons for our final decision on ElectraNet's regulatory depreciation allowance and depreciation schedule.

4.1 Final decision

We do not accept ElectraNet's regulatory depreciation allowance set out in its revised proposal. Table 4.1 sets out our final decision on ElectraNet's annual regulatory depreciation allowance for the 2013–18 regulatory control period.

Table 4.1 AER's final 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	78.9	89.3	104.8	116.5	119.0	508.5
Less: inflation indexation on opening RAB	51.7	56.5	59.4	62.6	64.9	295.2
Regulatory depreciation	27.1	32.8	45.4	54.0	54.1	213.4

Source: AER analysis.

4.2 Summary of analysis and reasons

We determine ElectraNet's regulatory depreciation allowance to be $213.4 million ($nominal) for the 2013–18 regulatory control period. Our final decision represents a reduction of $10.6 million (4.7 per cent) to ElectraNet's revised revenue proposal, which we made for the following reasons:

- We do not accept ElectraNet's revised depreciation schedule for the 'Transmission line refit—insulators replacement 2013–18' asset class. This is because we consider the expected economic life of the insulators should be much longer than the proposed 15 years. Consistent with our draft decision, we calculated a weighted average of the standard asset life of 27 years by weighting together the technical lives of the insulators using the proportion of capex for each insulator type as weights. We consider that a standard asset life of 27 years results in a depreciation profile that reflects the nature of the assets over the economic life of the assets

[31] NER, clauses 6A.5.4(a)(1) and (3).
[32] NER, clause S6A.1.3(7).
[33] NER, clauses 6A.6.3(b)(1) and (2).

within this asset class.[34] We agree with ElectraNet that when the underlying transmission assets are decommissioned, reusing those insulators may not be cost effective, given the high labour costs and other costs of redeployment. However, we consider it reasonable to expect that ElectraNet could extend the economic life of the underlying transmission line assets over time so that the insulators could be in service until the end of their expected technical lives. However, if ElectraNet cannot extend the lives of specific underlying assets through its asset management strategies, then it could propose to write off the residual value of the insulators when the underlying line assets are decommissioned.

- In accepting ElectraNet's proposed weighted average method to determine the remaining asset lives, we have updated ElectraNet's remaining asset lives as at 1 July 2013. This is to reflect our adjustments to the roll forward of the RAB in the roll forward model (RFM), as discussed in attachment 5. We also adjusted the remaining asset life roll forward formula in the revised RFM to exclude input values for assets under construction.
- Consistent with our draft decision, we accept ElectraNet's proposal to accelerate the depreciation of the residual values associated with replaced assets, such as substation and communications assets, for the 2013–18 regulatory control period. However, we have reduced the amount allocated for accelerated depreciation purposes to $4.0 million from the revised $5.8 million due to several error corrections.
- Our determinations on other components of ElectraNet's revised proposal also affect the regulatory depreciation allowance.[35] Discussed in other attachments, these determinations include the forecast capex (attachment 2) and the opening RAB as at 1 July 2013 (attachment 5).

34 NER, clause 6A.6.3(b)(1).
35 NER, clause 6A.6.3(a)(1).

5 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 in relation to new assets built to meet demand. The amount of capex and opex required by ElectraNet therefore partly depends on the expected level of demand.[36]

5.1 Final decision

The purpose of forecasting demand in a revenue proposal is to determine whether ElectraNet's forecast total capex meets the capex objectives including expected demand.[37] ElectraNet submitted a revised demand forecast in its revised revenue proposal in response to our draft decision. The difference between ElectraNet's revised forecast demand and our draft decision is not material. ElectraNet's augmentation and connection capex requirements do not vary materially if we apply the demand forecast set out in our draft decision as opposed to the demand forecast in ElectraNet's revised revenue proposal. Given that we accept ElectraNet's revised forecast augmentation and connection capex, we have not produced a full determination of forecast demand for the 2013–18 regulatory control period for our final decision.

ElectraNet's revised demand forecast

In its revised proposal, ElectraNet revised its demand forecast used to determine its load-driven capex.[38] ElectraNet stated its revised forecasts:[39]

- are based on a temperature related 10 per cent probability of exceedance (POE) and appropriately consider the uncertainty of temperature fluctuations on peak demand
- use appropriate adjustments to account for photovoltaic generation, embedded generation, and demand response in a 10 per cent POE framework
- contain appropriate diversity factors for use in regional network planning
- include a reconciliation with AEMO's 2012 state-wide summer demand forecasts.

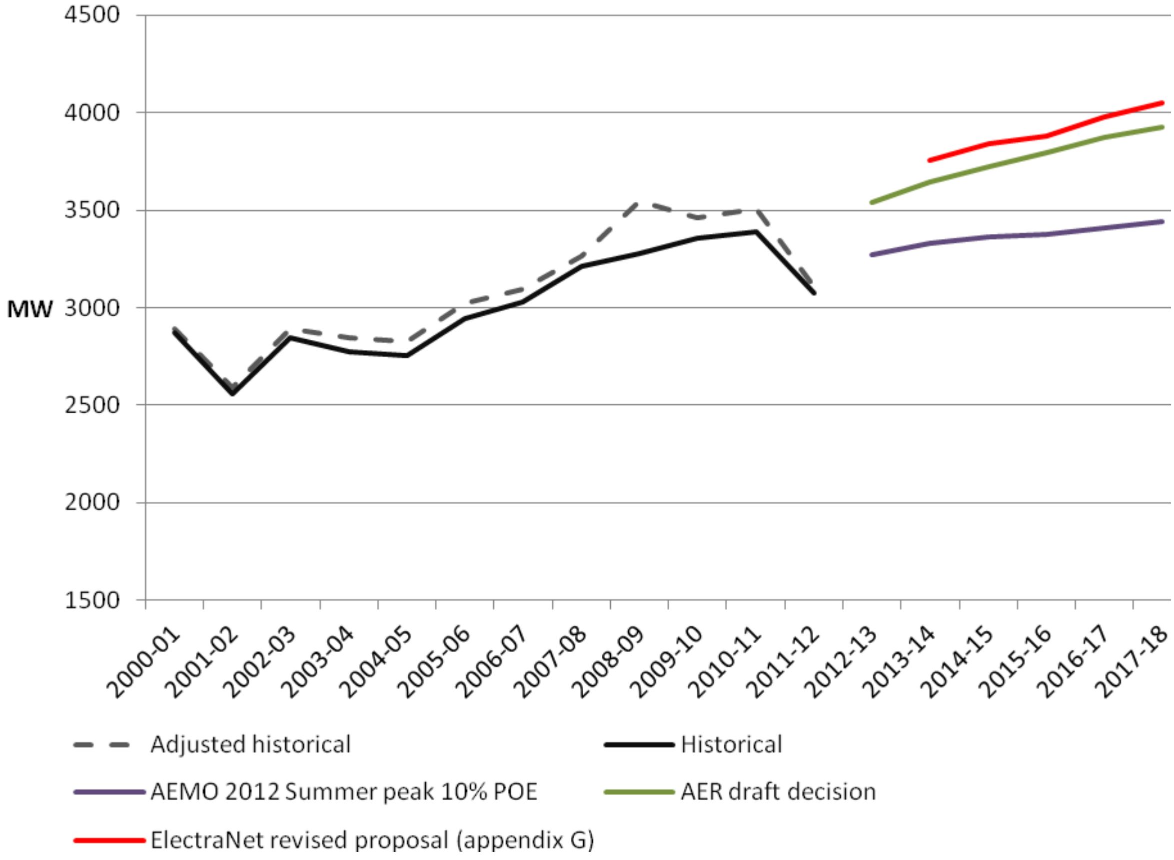
ElectraNet's revised proposal included a graph which showed its diversified state wide 10 per cent POE summer maximum demand forecasts.[40] The graph also included AEMO's state wide diversified demand forecast[41] and the AER's draft decision demand forecast.[42] ElectraNet stated its diversified state wide demand forecast was presented on a comparable basis to AEMO's diversified state wide forecast in order to demonstrate how the two forecasts reconcile. We note, however, that ElectraNet did not use its state wide diversified demand forecasts for determining its forecast total capex

36 However, unlike load driven capex, ElectraNet's opex is not directly related to demand.
37 NER, clause 6A.6.7(a).
38 ElectraNet, *Revised revenue proposal*, p. 22.
39 ElectraNet, *Revised revenue proposal*, p. 33.
40 ElectraNet, *Revised revenue proposal*, p. 32.
41 AEMO, *National electricity forecasts* 2012.
42 We note that ElectraNet mischaracterised our draft decision demand forecast (which is based on EMCa's check forecast) as a forecast that purports to be diversified. In fact, EMCa's check forecast is not diversified, but rather is the sum of the connection point demands. We describe this in section 5.4.3 of our draft decision. It is therefore not directly comparable to either ElectraNet's or AEMO's state wide diversified demand forecasts.

requirements in its revised revenue proposal. ElectraNet did not provide a graph that presented its revised demand forecast[43] against our draft decision.

Figure 5.1 sets out ElectraNet's revised demand forecast, our draft decision, and AEMO's 2012 state wide summer peak demand forecast.[44]

Figure 5.1 ElectraNet's revised demand forecast, AEMO's 2012 state wide summer peak demand forecast at 10 per cent POE and the AER's final decision demand forecast (MW).



Source: ElectraNet, *Revised proposal,* appendix G, January 2013; ElectraNet, *Summary CP historical and forecast peaks*, ENET0063, June 2012 [confidential]; ElectraNet*, Response to EMCa041 - Peak Load Data (Revised),* ENET244..

Table 5.1 shows our draft decision and ElectraNet's forecast demand for the 2013–18 regulatory control period as presented in its revenue proposal and its revised proposal.

[43] As set out in appendix G of ElectraNet's revised proposal.

[44] We note our draft decision and ElectraNet's revised proposal were not determined on the same basis as AEMO's state wide diversified demand forecast for 2012.

Table 5.1 **ElectraNet's proposed forecast demand and revised forecast demand and the AER's draft decision on ElectraNet's forecast demand for the 2013–18 regulatory control period (MW)**

	2013-14	2014-15	2015-16	2016-17	2017-18
ElectraNet revenue proposal	4077	4200	4321	4443	4553
AER draft decision	3644	3721	3797	3872	3928
ElectraNet revised regulatory proposal	3753	3841	3881	3979	4049

Source: ElectraNet, *Revenue proposal*, May 2012; ElectraNet, *Revised revenue proposal, appendix G;* AER*, draft decision, November 2012*.

ElectraNet did not provide a clear description of its revised forecasting methodology.[45] As a consequence we are not able to test the robustness of ElectraNet's revised demand forecast. ElectraNet provided a report from its consultants, Oakley Greenwood, in which Oakley Greenwood reviewed the reasonableness of the methodology and approach adopted by ElectraNet.[46] Oakley Greenwood's review did not include recalculation of specific outcomes nor an audit of data or analyses. While ElectraNet's consultant generally considered ElectraNet's demand forecast is reasonable it also identified a number of areas in which ElectraNet's demand forecasting methodology may be improved. In particular, Oakley Greenwood considered, overall, AEMO's treatment of photovoltaic penetration is likely to provide a more reasonable basis for deriving demand forecasts for ElectraNet.[47] The penetration of photovoltaic systems has been difficult for both ElectraNet and AEMO to forecast and both organisations are working to improve and reconcile their forecasting. Oakley Greenwood also stated that ElectraNet, in the longer term, should undertake a more robust analysis to derive the outputs of embedded generation at the time of connection point and state wide peak demand. It is not clear how ElectraNet has addressed the concerns expressed in our draft decision about embedded generation in its revised demand forecast.

[45] NER, clause S6A.1.1(2), (3) and (4).
[46] Oakley Greenwood, *Review of ElectraNet's revised demand forecasts*, January 2013.
[47] Oakley Greenwood, *Review of ElectraNet's revised demand forecasts*, January 2013, p.48.

6 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, we review actual capex undertaken during the current 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.

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.

The amount of overall capex required depends on the circumstances facing the service provider. Factors that influence the required level of capex include the age and condition of existing assets, and changes in both the number of customers connected to the network and demand profile of customers.

We assess capex forecasts against the requirements of the NER. We must accept the capex forecast if satisfied that it reasonably reflects the capex criteria. These are:

- the efficient costs to achieve the capex objectives, which are:[48]
  - 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
  - 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[49]
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.[50]

If we are not satisfied the forecast capex reflects the capex criteria, then we must not accept it , and must determine a substitute forecast capex.[51]

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

- asset management framework and policies
- business management systems and operations

48 NER, clause 6A.6.7(c)(1). Clause 6A.6.7 specifies the capex objectives.
49 NER, clause 6A.6.7(c)(2).
50 NER, clause 6A.6.7(c)(3).
51 NER, clauses 6A.6.7(d) and (f).

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

Our consultant, EMCa, also reviewed ElectraNet's proposed capex forecast. Attachment 2 sets out the detailed reasons for our final decision on ElectraNet's forecast capex.

6.1 Final decision

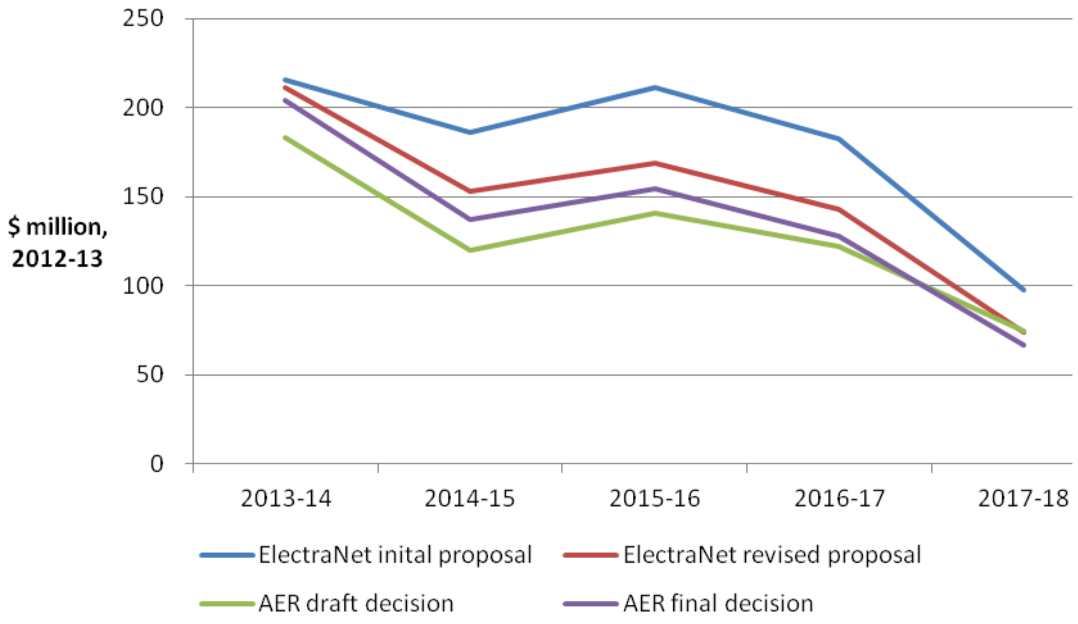
We do not accept ElectraNet's revised proposed total forecast capex of $750.1 million ($ 2012–13) for the 2013–18 regulatory control period. We estimated forecast capex of $690.7 million ($ 2012–13) which represents a reduction of $59.5 million ($2012-13) or 7.9 per cent on ElectraNet's revised proposal. Table 6.1 shows our final decision on ElectraNet's total forecast capex for the 2013–18 regulatory control period. Figure 6.1 shows ElectraNet’s initial and revised revenue proposal capex alongside the our draft and final decisions.

Table 6.1 AER final decision on ElectraNet's forecast capex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet's revised proposal	211.4	152.8	168.9	142.9	74.2	750.1
AER final decision	204.2	137.5	154.5	127.7	66.7	690.7
Difference	7.2	15.3	14.3	15.2	7.5	59.5

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

Figure 6.1 ElectraNet's initial and revised proposed capex and the AER's draft and final substitute total forecast capex allowances ($2012–13)



Source: ElectraNet, *Revenue proposal*, p. 76,;ElectraNet, *Revised capex model,* 8 February 2013; AER, *Draft decision, ElectraNet transmission determination*, November 2012, pp. 112; AER analysis.

6.2 Summary of analysis and reasons

We do not accept that ElectraNet's revised proposed total forecast capex satisfies the requirements of the NER and NEO or reflect the Revenue and Pricing Principles for the reasons outlined in attachment 2.[52] We consider ElectraNet's revised revenue proposal forecast does not meet the capex criteria. Consistent with our draft decision, we consider ElectraNet's asset management framework is consistent with good industry practice but consider ElectraNet's revised proposal has not sufficiently accounted for its own actions on continuous improvement. Consequently our final decision substitutes an allowance that we consider is consistent with the NER and NEL requirements.

We have undertaken additional analysis for our final decision to inform us of the issues raised by ElectraNet in response to our draft decision. This additional analysis included:

- further investigating ElectraNet's historical expenditure outcomes against forecast expenditures
- whether ElectraNet had sufficiently accounted for the benefits from investments in its integrated asset management framework
- the efficient and prudent level of strategic land and easement acquisitions.

On the basis of our assessment we consider ElectraNet's revised capex is overstated because it has not sufficiently taken into account relevant factors that drive an efficient and prudent expenditure forecast. Thus we have made adjustments to the following components of ElectraNet's capex forecast to develop a substitute forecast as required by the NER:[53]

- cost estimation risk factor and prudency adjustment

52 NER, clause 6A.14.1(2)(ii), NER, clause 6A.6.7(c), NEL, s.7 and s.7A.
53 NER, clauses 6A.14.1(2)(ii) and 6A.6.7(c); NEL, ss. 7 and 7A.

- capex/opex trade off
- real cost escalation
- strategic land and easement acquisitions.

Cost estimation risk factor

We do not accept ElectraNet's revised proposed cost estimation risk factor. The cost estimation risk factor is applied to capital projects that are still in concept stage and are yet to undergo a detailed cost build-up. It accounts for the risk that unforeseen factors will lead actual project costs to exceed initial cost estimates. We consider ElectraNet's proposed cost estimation risk factor overstates its capex requirement for the 2013–18 regulatory control period. Overall we consider the Evans & Peck analysis ElectraNet used to derive its proposed cost estimation risk factor is insufficiently transparent and thus unable to support robust conclusions.

For our final decision we undertook a detailed review of ElectraNet's actual historical outcomes. Our analysis demonstrates that at the portfolio level ElectraNet incurs actual costs approximately five per cent below that of its estimates. It also demonstrates that actual augmentation and connection capex project costs are about one per cent above estimates while replacement projects come in around 15 per cent lower than estimated levels. The outcome of this analysis is different from that proposed by ElectraNet in both its initial and revised regulatory proposals particularly in relation to its proposed 4.9 per cent cost estimation risk factor.

Based on our assessment of the Evans & Peck analysis and ElectraNet's actual historical outcomes we consider our substitute cost estimation risk factors account for ElectraNet's actions on continuous improvement. We consider these adjustments are consistent with our draft decision and reasonably reflect the efficient and prudent costs of maintaining the quality, reliability and security of supply of ElectraNet's prescribed transmission services.[54]

The application of our substitute cost estimation risk factors reduces ElectraNet's total capex forecast by $15.4 million ($2012–13).

Prudency adjustment

We do not accept ElectraNet's revised proposal to not adopt the 7 per cent prudency adjustment set out in our draft decision. The prudency adjustment is not an efficiency adjustment. As projects transition through capital governance gateways from the initial concept stages to being fully scoped and approved, decisions on alternative options, project scope and delivery approaches are made. Some examples of alternative options can include deferrals and integrations with other projects. In making these decisions at each gateway a TNSP can be expected to consider compliance with the required standards at least cost. This involves the marrying of engineering judgement with good capital governance to derive a capex forecast consistent with the capex criteria. Our prudency adjustments account for such decision making. If not, the forecast will be based largely on concept stage estimates without sufficient consideration of prudent decision making over the regulatory control period.

ElectraNet's revised proposal did not accept the basis for our draft decision application of the prudency adjustment.[55] Thus it did not apply this adjustment in its revised revenue proposal. For our

[54] NER, clauses 6A.6.7(a)(3), (c)(1) and (2).
[55] ElectraNet, *Revised revenue proposal*, pp. 52–9.

final decision we undertook detailed analysis of ElectraNet’s historical outcomes against its previously proposed capex. We consider this analysis will inform us of the reasonableness of the prudency adjustment applied in our draft decision. We note ElectraNet's consideration that its historical outcomes can be used to inform forecast costs.[56]

We consider ElectraNet's revised proposed replacement and refurbishment capex is overstated for the 2013–18 regulatory control period. Our analysis demonstrates prudency gains as projects progress through ElectraNet's capital governance gateways. We consider our draft decision 7 per cent prudency adjustment provides a level of capex that reasonably reflects the efficient and prudent forecast to maintain the quality, reliability and security of supply of ElectraNet's prescribed transmission services. [57]

Our application of the 7 per cent prudency adjustment reduces ElectraNet's total replacement and refurbishment capex forecast by $23.8 million ($2012–13).

Capex–opex trade off

We have reduced ElectraNet's revised proposed replacement and refurbishment capex by $5.5 million ($2012–13) to account for the capex–opex trade off. Attachment 3 provides more detail on our considerations on this matter.

Real cost escalators

We do not accept that ElectraNet's real cost escalation reasonably reflects a realistic expectation of the cost inputs required to achieve the capex and opex objectives.[58] 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.

We consider ElectraNet would be over compensated for labour cost escalations if its revised revenue proposal forecasts were applied. Our forecast has more reliably captured the environment in which ElectraNet will incur its labour costs over the 2013–18 regulatory control period. Thus we have not accepted ElectraNet’s forecast and subsitituted our own as this reflects a realistic expectation of cost inputs ElectraNet requires to achieve the opex and capex objectives over the 2013–18 regulatory control period.

ElectraNet ’s revised proposal applied our draft decision for the following:[59]

- current enterprise agreement (EA) outcomes for labour cost escalation to 2013–14
- exchange rates and forecast inputs for material and land value escalation updated to reflect most recent data
- land type escalators applied to corresponding land and easement projects.

We have determined the substitute escalators, which reflect our considerations that exchange rates and forecast inputs for material escalation should be updated to reflect most recent data.

The application of our substitute real cost escalation factors reduces ElectraNet's total capex forecast by $6.0 million ($2012–13). Attachment 1 provides more detail on our considerations on this matter.

56 ElectraNet, *Revised revenue proposal*, pp. 53–4.
57 NER, clauses 6A.6.7(a)(3), (c)(1) and (2).
58 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
59 ElectraNet, *Revised revenue proposal*, chapter 3.

Strategic land and easements

We do not accept ElectraNet's revised revenue proposal proposed strategic land and easements capex of $41.5 million ($2012–13). Our final decision is to substitute ElectraNet's proposed strategic land and easements capex with $30.7 million ($2012–13). This substitute forecast is $10.7 million ($2012–13) less than ElectraNet's revised revenue proposal but $17.2 million ($2012–13) more than our draft decision.

Land parcels and easements are considered 'strategic' if they are purchased in advance of their need for a transmission project. In some cases the period between acquisition and their eventual use could be up to 30 years.[60] Despite this we consider strategic land and easement acquisitions can be appropriate if the expenditure is prudent and efficient, and therefore reflects the capex objectives and criteria in the NER.[61]

In total, ElectraNet proposed six land and easements acquisitions. We assessed each against the requirements of the NER and considered whether all, part or none of the proposed capex should be included in our substitute forecast.

Our assessment approach focused on whether a high risk of encroachment on the line route from urban or semi urban development could delay or prevent the acquisition of a land parcel or easement. ElectraNet also provided cost-benefit analysis assessing the merits of acquiring each land parcel and easement in the 2013–18 regulatory control period, as compared with delaying their acquisition.

Components of ElectraNet's revised capex proposal that the AER accepts

We accept the following capex categories in ElectraNet's revised proposal reasonably reflect the efficient and prudent costs of achieving the capex objectives:[62]

- augmentation
- connection
- security/compliance
- inventory spares
- business IT
- buildings and facilities.

ElectraNet's revised augmentation and connection capex is a $74.4 million ($2012–13) reduction of its initial revenue proposal which was $251.2 million ($2012–13). This reduction reflects ElectraNet's revised demand forecast. We consider ElectraNet's revised augmentation and connection capex is consistent with its revised demand forecast and the adjustments applied in our draft decision.

60 ElectraNet, Revised revenue proposal, Appendix I 'Strategic land acquisition business cases', 16 January 2013, p. 5.
61 NER, clause 6A.6.7(a)(c)(1) and (2).
62 NER, clauses 6A.6.7(c)(3) and (a).

7 Operating expenditure

Forecast operating expenditure (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. ElectraNet's opex is divided into controllable and non–controllable opex.

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

- the efficient costs to achieve the opex objectives, which are:[63]
  - 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
  - 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[64]
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[65]

If we are not satisfied that the forecast opex reflects the above criteria, then we must not accept the forecast opex and must determine a substitute forecast opex.[66]

EMCa, our consultants, also reviewed ElectraNet's proposed opex forecast. Attachment 3 sets out the detailed reasons for our final decision on ElectraNet's forecast opex.

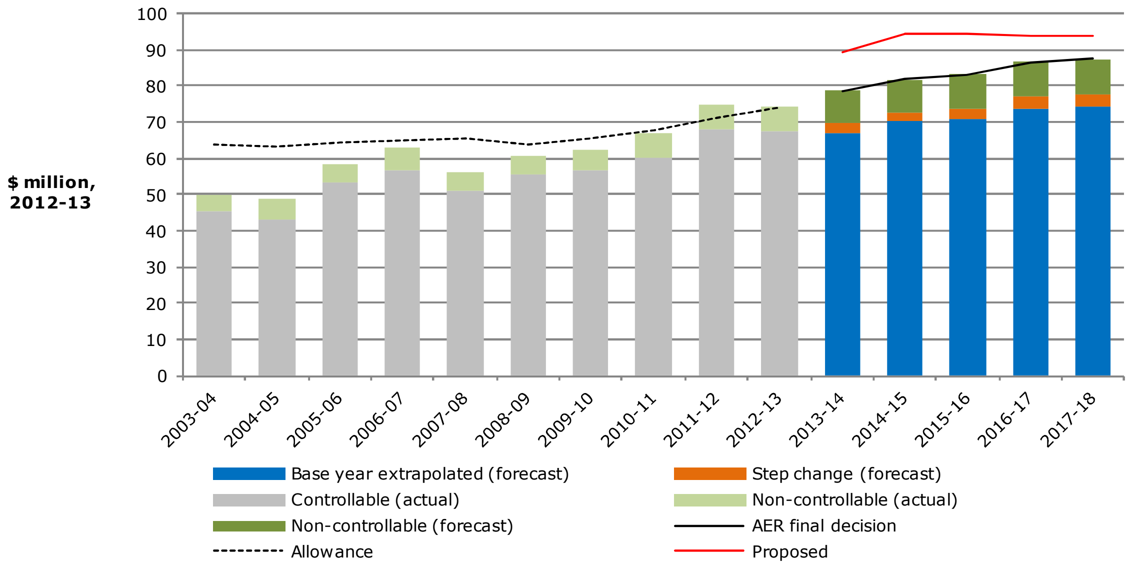
7.1 Final decision

We do not accept ElectraNet's revised revenue proposal opex forecast of $466.2 million ($2012-13)[67] for the 2013–18 regulatory control period because it does not meet the opex objectives or criteria.[68] We examined ElectraNet's proposal using different assessment methods which each found ElectraNet's revised forecast opex for 2013–18 is too high.

Our substitute forecast for the 2013–18 regulatory control period is $417.9 million ($2012-13). Figure 7.1 shows our forecast opex (black line) compared with ElectraNet's forecast opex (red line). This shows that ElectraNet's revised revenue proposal opex forecast is significantly above previous expenditure and the 2008–13 allowance (dotted black line). In percentage terms, our substitute forecast represents a real increase of 23 per cent on actual expenditure in the previous five years, whereas ElectraNet's revised proposal represents an increase of 37 per cent.

63 NER, clause 6A.6.6(a).
64 NER, clause 6A.6.6(c)(2).
65 NER, clause 6A.6.6(c)(3).
66 NER, clause 6A.6(d).
67 Unless otherwise stated, all dollars are in 2012-13 mid-year prices
68 NER, clause 6A.6.6 (a) and (c).

Figure 7.1 ElectraNet's total opex: actual, revised proposal and allowance, 2003–18 ($ million, 2012–13)



Note: 2012-13 is an estimate.
Source: AER analysis.

Table 7.1 compares our final decision on total opex with ElectraNet's opex proposal. Table 7.2 shows our opex decision by cost category and Figure 7.2 shows the composition of our opex decision.

Table 7.1 AER's final decision on total opex, 2013–18 ($ million, 2012–13)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
ElectraNet's revised revenue proposal	89.1	94.3	94.5	94.2	94.2	466.2
AER's decision	78.8	81.8	83.2	86.6	87.3	417.9
Difference	10.3	12.5	11.3	7.6	6.9	48.3

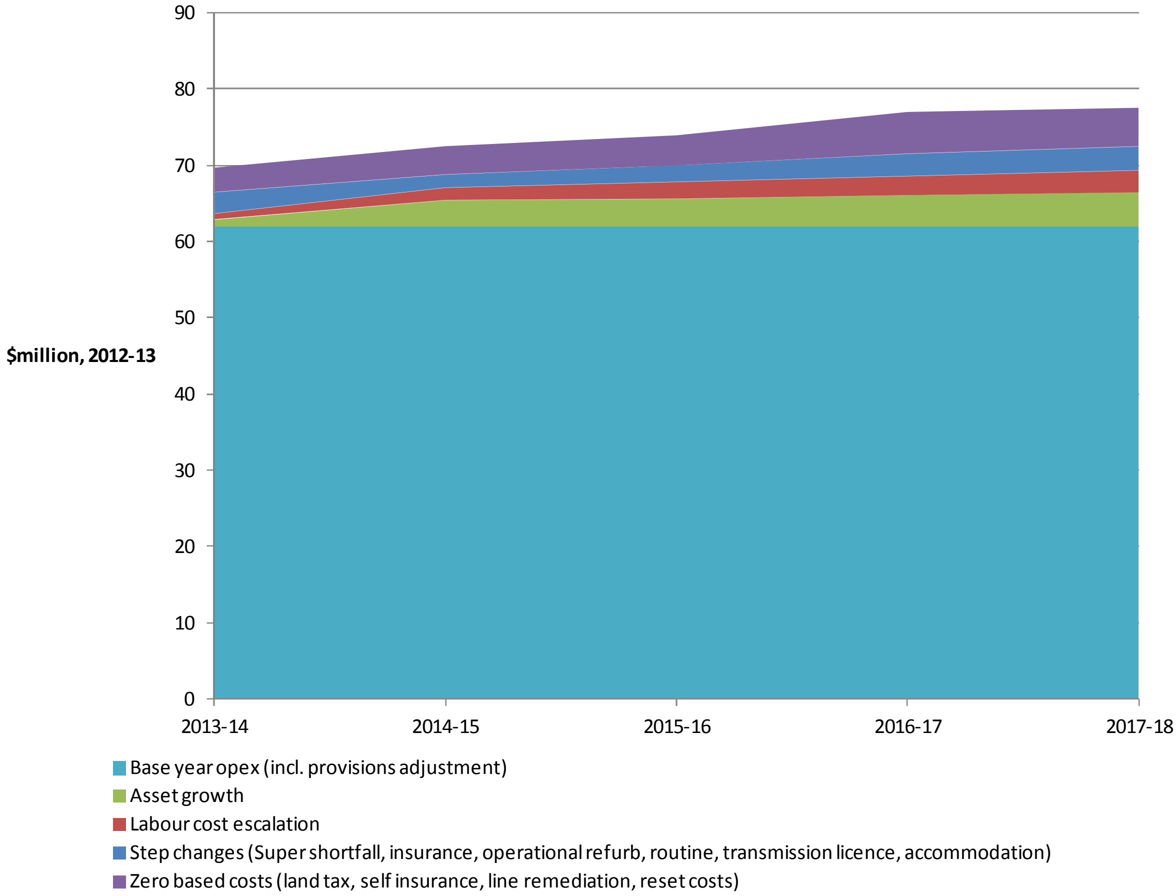
Source: AER analysis.

Table 7.2 AER's final decision on total opex, by cost category ($ million, 2012–13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Controllable opex						
Routine maintenance	15.0	15.5	15.7	17.0	17.8	80.9
Corrective maintenance	8.2	8.9	9.0	9.1	9.2	44.3
Operational refurbishment	9.4	9.6	10.2	9.8	9.9	48.9
Corrective maintenance-line remediation	0.8	1.2	1.2	1.2	0.5	4.8
Subtotal: field maintenance	**33.3**	**35.1**	**36.0**	**37.1**	**37.4**	**179.0**
Network operations	8.0	8.2	8.3	8.3	8.3	41.1
Maintenance support	10.3	10.8	10.9	11.1	11.3	54.4
Asset manager support	9.9	10.1	10.1	11.6	11.6	53.2
Corporate support	6.8	7.0	7.2	7.4	7.5	35.8
Self insurance	1.3	1.3	1.4	1.4	1.4	6.8
Total controllable opex	**69.6**	**72.5**	**73.9**	**76.9**	**77.5**	**370.4**
Non-controllable opex						
Network support	8.1	8.2	8.2	8.5	8.6	41.6
Debt raising costs	1.1	1.1	1.2	1.2	1.2	6.0
Total non-controllable opex	**9.2**	**9.3**	**9.4**	**9.7**	**9.8**	**47.6**
Total opex	**78.8**	**81.8**	**83.2**	**86.6**	**87.3**	**417.9**

Source: AER analysis.

Figure 7.2 Composition of AER's final decision on controllable opex ($ million, 2012-13)



Source: AER analysis.

7.2 Summary of analysis and reasons

Our analysis of ElectraNet's opex requirements covers their controllable and non-controllable operating costs. Most of ElectraNet's opex is controllable.

7.2.1 Controllable opex

We do not accept ElectraNet's proposed forecast controllable opex of $418.4 million ($2012-13)[69] because our review found it to be higher than necessary to meet the opex objectives or criteria.[70] Our substitute controllable opex forecast for the 2013–18 regulatory control period is $370.4 million ($2012-13).

We examined ElectraNet's proposal using two approaches: a top down approach using a base-step-trend method and a detailed bottom up technical review. Both reviews demonstrated ElectraNet's revised proposal was more than required to meet the NER opex objectives. We therefore substituted a forecast using the 'base-step-trend' approach, which is a well established top down approach to setting regulatory allowances in Australia. This approach uses actual expenditure in a base reference year which is then escalated for network growth, scale efficiencies and for real costs escalation. We substituted a forecast opex developed from the base year extrapolated method, but we also added some step changes to reflect ElectraNet's changing circumstances.

69 Unless otherwise stated, all dollars are in 2012-13 mid-year prices
70 NER, clause 6A.6.6(c).

Base year

We consider the base year should be a year in which expenditure was efficient and reflective of ongoing recurrent costs and likely prevailing economic conditions. We thus used the actual expenditure in 2010–11 as the reference for the base year because the actual controllable expenditure closely represented average expenditure for the whole current regulatory period for all opex categories. ElectraNet accepted this as a base reference year.

Step changes and other adjustments

After we determined ElectraNet's efficient base year costs, we added step changes and other adjustments. The step changes and other adjustments we approved are set out in Table 7.3.

Table 7.3 AER's approved step changes and other adjustments ($ million, 2012-13)

Cost category	Reason for step change
Routine maintenance	We accept ElectraNet's routine maintenance forecast of $80.9 million, which is effectively a step change increase of $9.0 million. ElectraNet has implemented a new asset management framework. This system allows faults to be detected before they become major problems. As a result more routine maintenance is expected. However, the increase in routine maintenance should result in reduced corrective maintenance and deferred asset replacement.
Operational refurbishment	We accept a step change of $1.0 million for operational refurbishment works to allow ElectraNet to defer substation replacement projects (with augmentation components) at Kingcraig and Keith substations.
Network optimisation (corrective maintenance–line remediation)	We accept ElectraNet's proposed $4.9 million to remediate high risk low hanging transmission line spans. We categorised this cost as corrective maintenance for line remediation. It is a one-off step-change which should be excluded from ElectraNet's future opex forecast beyond 2018.
Support categories	We added step changes for insurance and defined benefits. Transmission licence and new lease step changes are included in this category. The total net step increase is $12.9 million but the line items are discussed below.
Insurance	We accept the overall insurance forecast is reasonable. We added the difference of $2.4 million as a step change to the base year extrapolated allowance.
Defined benefits liability	We accept a step change of $2.4 million for ElectraNet's unfunded superannuation liabilities (the shortfall in defined benefits) which have increased in the current market environment. The contributions to defined benefits are influenced by exogenous factors and are outside ElectraNet's control.
Transmission licence fee	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 2013–18. We reduced ElectraNet's proposed opex forecast by $2.4 million accordingly.
New lease	ElectraNet added office accommodation costs to the base year. The impact of the step change after escalation was $1.0 million.
Movement in provisions	We applied a step decrease of $0.4 million to ElectraNet's base year opex to reverse the movement in provisions for future employee entitlements. This was an adjustment to the base year and the impact of the adjustment after escalation was –$2.0 million.
Land tax	We accept ElectraNet's revised land tax forecast of $13.0 million, which is $1.2 million more than our draft decision. The increased forecast reflects our final decision to approve more of ElectraNet's proposed strategic land purchases than we did in our draft decision. This is a zero-based adjustment.

Trend for network growth and real cost escalation

In assessing ElectraNet's opex requirements we take into account network growth and cost increases. We do this by escalating ElectraNet's base year opex. Table 7.4 shows the impact of AER escalation on controllable opex.

Table 7.4 Impact of AER escalation on controllable opex ($ million, 2012–13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Base year opex (incl. provisions adjustment)	62.0	62.0	62.0	62.0	62.0	310.2
Step changes and other adjustments	2.9	2.3	2.8	2.4	2.1	12.5
Labour cost escalation	0.7	1.6	2.2	2.5	2.8	9.9
Asset growth	0.9	3.4	3.6	4.1	4.5	16.4
Zero based costs (land tax, self insurance, line remediation, reset costs)	3.2	3.7	3.9	5.5	5.1	21.4
AER's final decision	69.7	73.2	74.6	76.5	76.5	370.4

Source: AER analysis.

Asset growth

We accept ElectraNet's revised method for forecasting asset growth factors. However, we have updated the asset growth factors to reflect our final decision on ElectraNet's load driven capex forecast, as discussed in attachment 2.

Economies of scale

As ElectraNet's network grows it will incur increasing operating costs but it will also be able to achieve some economies of scale. We adopt the same economies of scale factors as those used in ElectraNet's 2008–13 transmission determination. ElectraNet proposed increasing some scale factors indicating it would become less efficient with network growth. ElectraNet has not provided reasons why it cannot maintain its existing economy of scale efficiencies and would expect to become less efficient. However, we do accept direct charges should be applied at 100 per cent.

Real cost escalation

Forecast opex should provide for future cost increases. We achieve this by applying real cost escalators to base year operating expenditure. As outlined in attachment 1, we do not accept ElectraNet's proposed real cost escalators but applied lower escalators which reduced ElectraNet's total opex requirements.

ElectraNet's proposed forecast

ElectraNet's revised controllable opex forecast was $418.4 million, which is $48 million more than our substitute forecast, including step changes. ElectraNet's proposal is higher than our forecast because it includes step changes and bottom up forecasts that we have not accepted. We do not accept these additional elements because we consider they are already captured in the base year or in step changes we have approved. To allow this additional opex would be to double count expenditure requirements.

Back log of defects

ElectraNet proposed additional corrective maintenance to clear a backlog of defects. However, we consider the base year forecast already provides for ElectraNet to efficiently manage its backlog. This is because ElectraNet's 2008–13 allowance included a one-off allowance to clear substation maintenance backlogs. Our forecast, which allowed for the substation backlogs in the expenditure of the base year, can now be allocated by ElectraNet to address its identified transmission line backlog. Our consultant (EMCa) considered ElectraNet's aim to entirely eliminate its backlog of defects to be unrealistic and unnecessary and is a more aggressive strategy than it is currently applying. Further, we consider ElectraNet has overestimated its forecast corrective maintenance costs because it overestimated its incoming defect rates which should decline over time. The incoming rate of defects should reduce as high risk defects identified in the first cycle are rectified, leaving lower and less urgent risks to be corrected.

Operational refurbishment

ElectraNet did not demonstrate any additional adjustment that is required for its proposal to meet the NER criteria or NEL pricing principles. The remainder of the operational refurbishment program consists of packaged programs of works or projects. Our substitute forecast for operational refurbishment is a top down assessment and does not make any particular judgement on which projects or programs might practically differ from the program put forward by ElectraNet. These projects do not include high risk defects (these are undertaken in a shorter timeframe as corrective maintenance). It includes some medium and low risk defects that ElectraNet determined will need to be addressed in the 2013–18 regulatory control period. Operational refurbishment projects justified by operational needs only (reliability and interruptions) should be tested by cost-benefit analysis against other options. ElectraNet did not demonstrate the economic case for a step change.

Lines assessments

We are satisfied that our base-year-extrapolated approach with step changes, provides ElectraNet sufficient allowance to undertake prudent management of the scope and condition monitoring activities. ElectraNet forecast costs for transmission line assessments (part of its implementation of the asset management framework) as part of its operational refurbishment program. However, the base year included condition assessment expenditure for transmission lines so our base-year-extrapolated forecast covers this type of activity.

Capex–opex trade off

The principle of the capex–opex trade off is to recognise that consumers should be able to receive the benefits of their investment in ElectraNet's enhanced asset management framework in a reasonable timeframe.

Our final decision is to apply a capex–opex trade off adjustment of $5.5 million ($2012–13) to ElectraNet's replacement capex forecast. In coming to this decision, we considered ElectraNet's response to our draft decision and EMCa's technical advice. We revised the amount of the capex–opex trade off adjustment from $50 million ($2012–13) in our draft decision based on the issues set out in this section and information submitted by ElectraNet.

As discussed in attachment 3 of our draft decision, we observed that ElectraNet's proposal contained increases in opex and replacement/refurbishment capex largely driven by ElectraNet's improved asset management framework. The key issue for our assessment is whether the consumer's investments in

ElectraNet's enhanced asset management framework, which drives significant forecast expenditure increases, resulted in efficient expenditure forecasts consistent with a prudent operator.

Our draft decision considered ElectraNet's enhanced asset management framework and design is consistent with good industry practice and that the investment in the framework is capable of delivering material benefits to ElectraNet and its customers. ElectraNet's enhanced asset management framework applies the principles of condition based asset management and is a fundamental component of its strategic approach to managing its network. However, ElectraNet has not sufficiently factored the expected benefits of the framework into its revised regulatory proposal. As a result, the revised proposed expenditure is overstated and does not satisfy the opex and capex criteria.[71] In this context, although the full economic benefits have not been demonstrated, we approved scope changes to the field maintenance opex category. This results in an opex allowance increase above the revealed cost forecast.

At the same time, we expect 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, we consider 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. Thus, consistent with our draft decision, we have made a capex–opex trade off adjustment to account for the benefits consumers should receive from their investment in ElectraNet's integrated asset management framework. This adjustment is based on the incremental costs of the deployment of ElectraNet's enhanced condition based maintenance regime (the regime) and taking into account the quantifiable benefits.

ElectraNet's revised proposal disputed the application of the capex–opex trade off for the following reasons:

- ElectraNet's forecast already accounts for capex deferrals
- our draft decision overstated the incremental costs of the regime
- the capex–opex trade off adjustment is an ex–post adjustment.

ElectraNet considered its forecast already accounts for $275 million benefits of capex deferrals. EMCa reviewed this claim and considered that the capital to be deferred from 2007 to 2019 is likely to be at most $11.2 million. We accept that ElectraNet accounted for at most $11.2 million ($2012-13) of capex deferred from its expenditure forecast and we have revised our calculations accordingly.

ElectraNet further considered the incremental costs of the regime to be $30.1 million ($2011–12) but did not provide a justification for its cost estimate, method or assumptions. ElectraNet provided this estimate only in response to our draft decision and this estimate appears to contradict other material it submitted. EMCa found the incremental costs of the program to be $46.3 million ($2012-13) which includes the line condition assessment expenditure proposed by ElectraNet. Our estimate of the incremental costs of the program is $40.1 million, which includes the line condition assessment allowance of our base-step-trend forecast.

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

Finally, ElectraNet stated that we are not in a position to apply an ex–post adjustment for prior period expenditure. While we acknowledge ElectraNet's statement, we consider the capex–opex trade off is not an ex–post adjustment. Rather we consider the principle of this adjustment is to recognise that the benefits should at least match the investment costs in a reasonable timeframe and, that the timeframe is likely to be around ten years.

7.2.2 Non-controllable costs

ElectraNet has two types of non-controllable opex costs, debt raising costs and network support.

Debt raising costs

Our draft decision accepted ElectraNet’s proposed method for determining its benchmark costs allowance associated with its forecast opex. We consider this method provides estimates of the debt raising costs that would be incurred by a prudent service provider, acting efficiently. This is because the approach:

- identifies the types of transaction costs that a prudent service provider acting efficiently would incur in raising debt
- quantifies the level of these costs (using benchmark assumptions that also takes into account the specific circumstances of the service provider) with reference to market rates for the relevant services.

We have updated ElectraNet's proposed debt raising cost allowance to reflect our final decisions on the opening RAB (debt component) and WACC. Our final decision, therefore, is to provide ElectraNet an allowance for debt raising costs of $6.0 million ($2012–13).

Network support

We accepted ElectraNet's proposed allowance of $41.6 million for network support for the 2013-18 regulatory control period in our draft decision. 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. 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.

8 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) operates in conjunction with the ex ante incentive framework, to provide TNSPs with a continuous incentive to reduce opex. It provides this incentive by allowing a TNSP to retain efficiency gains for five years before passing them on to consumers. We must decide:

- the carryover amounts that will arise from applying the EBSS during the 2008–13 regulatory control period
- how the EBSS will apply to ElectraNet in the 2013–18 regulatory control period.

Attachment 12 sets out the detailed reasons for our final decision on the EBSS.

8.1 Final decision

We are not satisfied ElectraNet's revised proposed EBSS carryover of –$0.8 million ($2012–13), from the application of the EBSS during the 2008–13 regulatory control period, complies with the scheme requirements. We consider a carryover of –$1.8 million ($2012–13) complies with the scheme. Table 8.1 outlines the carryover amounts that we will include as building blocks to determine ElectraNet's annual revenue requirement.

Table 8.1 AER's final decision on EBSS carryover amounts for 2008–13 regulatory control period ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
EBSS carryover amount	–1.3	–3.4	–1.3	0.0	4.3	–1.8

For the application of the EBSS during the 2013–18 regulatory control period, our final decision is:

- not to adjust total forecast opex if actual demand growth in 2013–18 is different from forecast demand growth
- to exclude the following cost categories for the calculation of EBSS carryover amounts for the 2013–18 regulatory control period:
    - debt raising costs
    - network support costs
    - self-insurance costs
    - land tax
    - additional regulatory reset costs
    - superannuation defined benefits contributions.

We will also adjust actual opex for the 2013–18 regulatory control period to reverse any movements in provisions. This is consistent with the approach we used to forecast opex for the period.

Table 8.2 shows the total opex forecasts that we will use to calculate efficiency gains and losses for the 2013–18 regulatory control period.

Table 8.2 AER's final decision on ElectraNet's forecast opex for EBSS purposes ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Total forecast opex	78.8	81.8	83.3	86.7	87.3	417.9
Total adjustments	–14.4	–14.5	–14.5	–16.5	–16.5	–76.4
Forecast opex for EBSS purposes	**64.4**	**67.3**	**68.8**	**70.2**	**70.9**	**341.5**

8.2 Summary of analysis and reasons

We are not satisfied ElectraNet's revised EBSS carryover penalty of $0.8 million complies with the scheme, because the calculation does not incorporate our decision regarding movements in provisions.

Movements in provisions

The EBSS requires the AER to measure actual opex using the same method used to calculate the forecast opex for the same regulatory control period. We removed movements in provisions from ElectraNet's base year expenditure to determine ElectraNet's forecast opex in this final decision. Therefore, any movements in provisions in ElectraNet's actual opex during the 2013–18 regulatory control period should be excluded from the calculation of EBSS carryovers.

Because we reversed movements in provisions from forecast and actual opex for the EBSS carryover calculation for the 2013–18 regulatory control period we must apply a consistent approach to applying the EBSS to the 2008–13 regulatory control period. This is necessary to reward TNSPs for efficiency gains and to penalise them for efficiency losses.

Excluded cost categories

When we apply the EBSS to the 2013–18 regulatory control period we will exclude the cost categories listed in attachment 10 because they are not forecast using historical expenditure in an efficient base year. Since our draft decision, we have added superannuation defined benefits contributions as an excluded cost category. We did this because we accepted the contributions as an additional step change in our final opex decision and they are not forecast using historical expenditure in an efficient base year.

9 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 our post–tax revenue model (PTRM).

We use the PTRM to produce an estimate of the taxable income that would be earned by an efficient company operating the South Australian transmission network. 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. We then apply a discount to this to account for the assumed utilisation of imputation credits. This estimated tax amount is then included as a separate building block to determine ElectraNet's total revenue. This amount enables ElectraNet to recover the costs associated with the estimated corporate income tax payable during the 2013–18 regulatory control period.

Attachment 7 sets out the detailed reasons for our final decision on ElectraNet's estimated cost of corporate income tax.

9.1 Final decision

We do not accept ElectraNet's estimated cost of corporate income tax allowance set out in its revised proposal. Table 9.1 sets out our final decision on ElectraNet's estimated corporate income tax allowance for the 2013–18 regulatory control period.

Table 9.1 AER's final decision on ElectraNet's corporate income tax allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Tax payable	14.9	16.1	17.0	19.0	16.7	83.7
Less: value of imputation credits	9.7	10.4	11.1	12.3	10.9	54.4
Net corporate income tax allowance	5.2	5.6	6.0	6.6	5.9	29.3

Source: AER analysis.

9.2 Summary of analysis and reasons

We determine the estimated corporate income tax allowance of ElectraNet to be $29.3 million ($nominal), which represents an increase of $1.2 million (or 4.3 per cent) to the revised proposal. This increase has been made for the following reasons:

- We do not accept ElectraNet's revised opening tax asset base (TAB) as at 1 July 2013 of $1352.8 million. This is due to the adjustments we made to the actual capex in the RFM as discussed in attachment 5.
- We accept the majority of ElectraNet's revised standard tax asset lives for its asset classes, except for the 'Transmission line refit—insulators replacement 2013–18' asset class. We changed the revised standard tax asset life for this asset class to 27 years from 15 years to be consistent with our final decision on the standard asset life for this asset class for regulatory depreciation purposes.

- We accept ElectraNet's weighted average method to calculate the remaining tax asset lives at 1 July 2013 in its revised proposal. This weighted average method was accepted in our draft decision.[72] For this final decision, we have updated the proposed remaining tax asset lives to reflect our adjustments to ElectraNet's actual capex for 2007–08 to 2012–13 in the RFM.[73]
- Our determinations on other building blocks including forecast opex (attachment 3) and cost of capital (attachment 4) also impact the estimated corporate income tax allowance.[74]

72 AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 190.

73 2012–13 capex is an estimated value.

74 NER, clause 6A.6.4.

10 Contingent projects

Contingent projects are significant network augmentation projects that may arise during the regulatory control period but are neither yet committed nor 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'.[75] The occurrence of the trigger event must be probable.[76] However, the event or the costs associated with the event must be uncertain.[77] 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.[78] For this reason, the trigger event must be adequately defined and the proposed contingent capex must reasonably reflect the capex criteria under the NER.[79]

Attachment 11 sets out the detailed reasons for our final decision on contingent projects.

10.1 Final decision

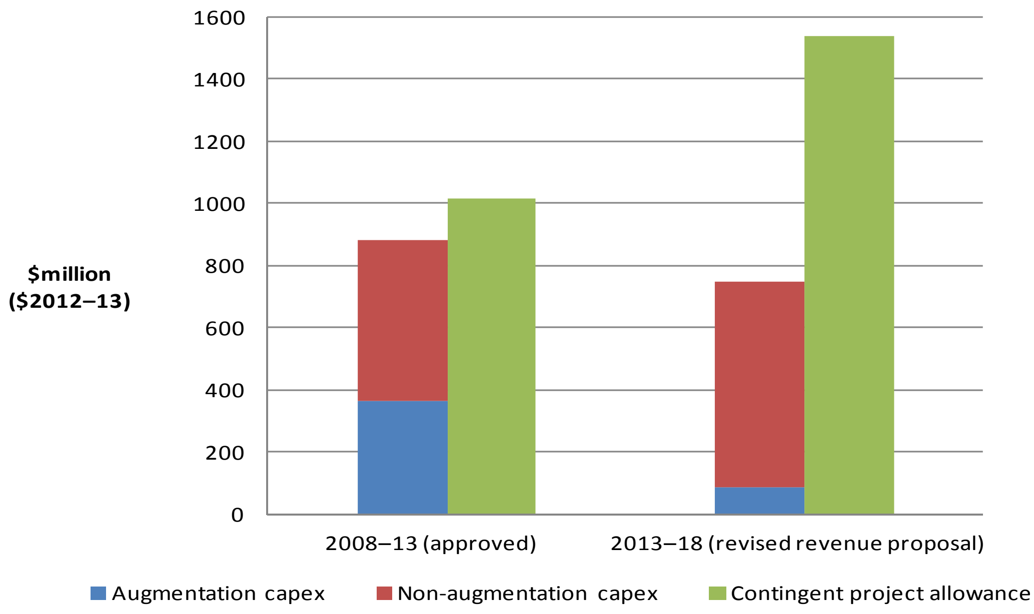
We accept all of ElectraNet's proposed contingent projects except the 'Northern Suburbs reinforcement' project ($50 million, $nominal).[80] We accept eleven of ElectraNet’s proposed contingent projects because they satisfy the requirements of the NER. For some of these projects, we have modified the trigger events because we were not satisfied that ElectraNet's proposed trigger events satisfied the NER requirements. We are satisfied that each of the accepted contingent projects exceed the threshold set out in the NER, being the larger of $10 million or 5 per cent of the MAR for the first year of the regulatory control period.[81]

10.2 Summary of analysis and reasons

ElectraNet proposed $1540 million of contingent capex in its revised revenue proposal.[82] By comparison, ElectraNet proposed $750.1 million of capex in its revised revenue proposal.[83] The eleven contingent projects that the AER accepted in its final decision include $1490 million of contingent capex.[84] Figure 10.1 compares ElectraNet’s proposed contingent capex with its proposed capex allowance.

75 NER, clause 6A.8.1(c)(5).
76 NER, clause 6A.8.1(c)(5).
77 NER, clause 6A.8.1(c)(5)(i).
78 NER, clauses 6A.8.1(c)(4); 6A.8.2.
79 NER, clause 6A.8.1(b)(2)(ii).
80 All proposed contingent capex is in nominal dollars.
81 NER, clause 6A.8.1(b)(2)(iii).
82 ElectraNet, Revised revenue proposal, pp. 176–179.
83 Revised capex model, 8 February 2013.
84 ElectraNet is only allowed to recover contingent capex after it applies to the AER to amend the revenue determination in accordance with clause 6A.8.2 of the NER.

Figure 10.1 Comparison of capex and contingent project allowances from 2008–13 transmission determination and ElectraNet's revised revenue proposal



Source: AER analysis.
Note: the proposed contingent capex are in nominal dollars.

For the final decision, we have grouped the proposed contingent projects into two categories:

- Load driven proposed contingent projects
- Non-load driven proposed contingent projects.

10.2.1 Load driven proposed contingent projects

Load driven proposed contingent projects includes seven proposed contingent projects which we identified were driven by specific step changes in demand at particular points on the ElectraNet network.

We do not accept the 'Northern Suburbs reinforcement' project as a contingent project because the trigger event is not probable during the 2013–18 regulatory control period.[85] ElectraNet's description of the trigger event for this project referred generally to additional residential, commercial and industrial development, as driving this project. We consider that all of these items are organic load growth which are captured under the demand forecast. We could not identify a specific event which would result in a step change in demand which would require this project to be undertaken before 2021.

We do accept that ElectraNet's six other load driven proposed contingent projects satisfy the NER:

- Upper North Region line reinforcement ($60 million)
- Lower Eyre Peninsula reinforcement ($340 million)

85 NER, clause 6A.8.1(c)(5).

- Yorke Peninsula reinforcement ($190 million)
- East Terrace transformer ($23 million)
- Mid North connection point ($60 million)
- Port Pirie system reinforcement ($52 million).

Due to their similarity these six projects are considered together. We are satisfied that ElectraNet has identified a specific underlying driver which would make the trigger event for these projects probable.[86] ElectraNet identified specific underlying drivers that would cause a step change in demand. We are also satisfied that these proposed contingent projects are not provided for under ElectraNet's capex forecast and therefore accept these six proposed contingent projects in our final decision.

10.2.2 Non–load driven proposed contingent projects

This category includes five proposed contingent projects which we identified were not driven by demand increases but rather were driven by other events. We accept all five non-load driven proposed contingent projects included in ElectraNet's revised revenue proposal:

- South East to Heywood interconnection upgrade ($63 million) — ElectraNet amended its proposed trigger event for this project in its revised revenue proposal to be consistent with our draft decision.
- Upper South East network augmentation ($50 million) — ElectraNet provided additional information about the proposed generation and the likely connection load.[87] Should this generation come on line then this project will go ahead. ElectraNet's revised revenue proposal also proposed that publication by AEMO of evidence of material constraints in the upper south east of ElectraNet's network would prompt ElectraNet to consider market benefits in addressing this issue.
- Riverland Reinforcement ($400 million) — ElectraNet amended its proposed trigger event for this project in its revised revenue proposal to be consistent with our draft decision. ElectraNet also removed the trigger event for this project that was associated with a step change in demand.
- Davenport Reactive Support ($42 million) — ElectraNet amended its proposed trigger event for this project in its revised revenue proposal to be consistent with our draft decision.
- Fleurieu Peninsula reinforcement ($210 million) — While ElectraNet's proposed trigger event refers to demand growth, we have found that the proposed contingent project is not driven by the demand increase. Rather, this project will only be required if the non-network solution fails.[88] We consider that this is the real driver of the project. If the non-network solution does not occur the project will be reasonably required.

We are therefore satisfied that these proposed contingent projects are appropriate and accept these five proposed contingent projects in our final decision.

86 NER, clause 6A.8.1(c)(1).
87 ElectraNet, Contingent projects, ENET347, p. 4 [Confidential].
88 ElectraNet, Contingent projects, ENET347, p. 3 [Confidential].

11 Service target performance incentive scheme

The service target performance incentive scheme (STPIS) has two components: the service component and the market impact component. Together, these two components counter the financial incentive under revenue regulation to reduce costs at the expense of service performance. A TNSP's annual performance is compared against the performance target for each parameter during the regulatory control period. Under the service component the TNSP may receive a financial bonus for service improvements, or incur a financial penalty for declines in service performance. The market impact component is a financial bonus only scheme. The financial bonus (or penalty) for the service component is limited to 1 per cent of the TNSP's maximum allowed revenue (MAR) for the relevant calendar year. The financial bonus for the market impact component is limited to 2 per cent of the TNSP's maximum allowed revenue (MAR) for the relevant calendar year.

Attachment 9 sets out the detailed reasons for our final decision on the STPIS.

11.1 Final decision

Service component

We do not accept ElectraNet's revised revenue proposal service component parameter weightings. Table 11.1 shows our final decision on ElectraNet's proposed service component parameter values and weightings.

Table 11.1 AER final 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.

Market impact component

ElectraNet incorporated our draft decision in its revenue proposal. Table 11.2 shows our final decision on ElectraNet's proposed market impact component target and cap.

Table 11.2 AER final 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 Summary of analysis and reasons

ElectraNet incorporated all of our draft decision on the STPIS except for our draft decision on the revenue weightings to apply to the ‘loss of supply events > 0.05 system minutes’ and ‘average outage duration’ parameter.

Revenue weightings for service component parameters

We do not accept ElectraNet's proposed weightings for the 'loss of supply event > 0.05 system minutes' sub–parameter and the 'average outage duration' parameter. Given the current revenue weighting for the 'average outage duration' parameter has incentivised an improved performance, ElectraNet should provide clear evidence or reasons why it considers the incentive should be increased. ElectraNet did not provide this evidence. The current revenue weighting of 0.2 per cent remains appropriate to incentivise and maintain 'average outage duration' performance. We consider that an increase in the weighting for the 'loss of supply events > 0.05 system minutes' sub–parameter is warranted given performance in 2010–12 was poorer than for 2008–09.

12 Pricing methodology and negotiated services

We must approve a pricing methodology and negotiating framework for ElectraNet, and determine the negotiated transmission service criteria (NTSC) to apply to it over the 2013–18 regulatory control period.

12.1 Final decision

We uphold our draft decision approving ElectraNet's proposed pricing methodology. We approve ElectraNet's proposed negotiating framework because, following its incorporation of our suggested revisions,[89] it meets the requirements of the NER.[90] We affirm that the NTSC specified in our draft decision[91] reflect the negotiating service principles[92] and will take effect at the commencement of the 2013–18 regulatory control period.

89 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 267
90 NER, clause 6A.9.5(c)
91 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 267
92 NER, clause 6A.9.1

13 Cost pass throughs

The pass through mechanism of the National Energy Rules (NER) recognises a TNSP can be exposed to risks beyond its control, which may have a 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 for which the transmission determination does not account.

We must decide which of the pass through events ElectraNet nominated, will apply for the 2013–18 regulatory control period. Attachment 16 sets out the detailed reasons for our final decision.

13.1 Final decision

The following three nominated pass through events will apply to ElectraNet in the 2013–18 regulatory control period:

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

We accept the terrorism event definition as proposed by ElectraNet but we have amended the natural disaster event and the insurance cap event definitions.

We do not accept the additional proposed pass through event ElectraNet submitted in its revised proposal. ElectraNet defined the event as an event '*that would be triggered by a decision from ESCOSA that results in a more onerous forecast demand obligation under the ETC*'.

13.2 Summary of analysis and reasons

In considering the pass through events that ElectraNet nominated in its revised proposal, we had regard to:

- the efficient allocation of risk
- the nominated pass through event considerations in the NER
- advice provided by AM actuaries.[93]

Our starting point for considering pass through events is the provision of appropriate incentives to promote efficient and prudent risk management. The aim is thus to align the financial risks of providing network services with those best able to manage those risks – namely, the TNSP. So, a nominated cost pass through mechanism is intended to ensure the efficient funding of risks when it is uneconomical for the service provider to get insurance cover or be paid a self insurance allowance. A pass through event should be approved only when the potential financial damage of the event is so extreme that it is effectively deemed not insurable.

Terrorism event

We accepted ElectraNet's proposed definition of a terrorism event in our draft decision because it is consistent with the nominated pass through event considerations.

[93] We engaged AM Actuaries to provide technical advice on nominated pass through event policy considerations.

Natural disaster event

Our draft decision required the natural disaster to be a 'major' fire, flood, earthquake or other natural disaster. However, ElectraNet considered the revision was not necessary because if the materiality threshold (1 per cent of the maximum allowed revenue for that year) is met, then the event is clearly a major event. We disagree with ElectraNet's interpretation of 'major' so we include the meaning of 'major' in our final definition. We consider 'major' means an event that is serious or significant: it does not mean 'material'. If the costs of non major natural disaster events are able to be passed through, an unacceptable amount of manageable and affordable risk will be transferred from ElectraNet to its customers.

Insurance cap event

ElectraNet contested two aspects of the insurance cap event definition in our draft decision, and proposed amendments to address them. We agree with these amendments. We also include an amendment to clarify that the costs that ElectraNet incurs beyond the relevant policy limit are those costs that would have been recovered under the insurance policy limit had the limit not been exhausted.

Additional pass through event

We do not accept the additional nominated pass through event that ElectraNet proposed in its revised proposal.[94] ElectraNet defined the event as an event '*that would be triggered by a decision from ESCOSA that results in a more onerous forecast demand obligation under the ETC*'.[95]

We do not accept the proposed event, because ElectraNet submitted this pass through event after the date permitted by the NER under the transitional arrangements which allowed it to nominate cost pass through events as part of its revenue proposal.[96]

Alternatively, ElectraNet also submitted that we, on our own accord should approve an appropriate pass through event as part of our final decision. However, we do not accept this alternate proposal, because:

- ElectraNet did not clearly identify the nature or type of event[97]
- the NER already provides pass through events that may allow ElectraNet to recover additional capital costs incurred as a result of a regulatory change event or a service standard event.[98]

94 ElectraNet, *Revised revenue proposal*, p. 36.
95 ESCOSA is the Essential Services Commission of South Australia. The ETC is the South Australian Electricity Transmission Code, TC/07, effective 1 July 2013.
96 NER, clause 11.49.4.
97 NER, Chapter 10, Glossary, *nominated pass through event considerations*, 6A.7.3(a1)(5).
98 Chapter 10, Glossary, nominated pass through event considerations, 6A.7.3(a1)(5).

Part 2 – 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 Final decision

Overall, we do not accept ElectraNet's revised proposed real cost escalators reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[99] Therefore we have determined the substitute escalators in table 1.1, which reflect our 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.

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

	2013-14	2014-15	2015-16	2016-17	2017-18
Internal labour	2.0	2.0	0.4	0.6	0.9
External labour	0.9	0.7	0.4	0.1	0.6
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	5.4	2.8	3.7	6.4	6.7
Copper	2.4	0.9	0.7	–3.0	–8.8
Steel	5.4	5.5	0.1	–0.8	1.8
Crude oil	3.1	–3.9	–3.3	–2.3	–1.6
Construction	0.4	–0.2	0.4	0.3	0.0
Weighted average material	2.1	1.8	0.4	0.3	0.6

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

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

1.2 ElectraNet's revised proposal

ElectraNet applied our draft decision for the following:

- current enterprise agreement (EA) outcomes for labour cost escalation to 2013–14
- exchange rates and forecast inputs for material and land value escalation updated to reflect most recent data
- land type escalators applied to corresponding land and easement projects.

ElectraNet however did not accept our draft decision on labour cost escalation. Table 1.2 provides ElectraNet's revised real cost escalation forecasts.

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

	2013-14	2014-15	2015-16	2016-17	2017-18
Internal labour	2.0	2.0	2.1	2.4	2.4
External labour	2.4	3.7	3.0	2.5	2.5
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	6.9	4.4	3.4	3.0	2.7
Copper	1.7	0.3	–2.6	–3.6	–4.0
Steel	2.8	3.1	0.8	0.8	0.5
Crude oil	1.0	–0.9	–1.4	–0.9	–0.6
Construction	–0.1	0.4	0.4	0.1	0.1
Weighted average material	2.1	2.3	1.8	1.8	1.7

Source: ElectraNet, *Revised capex model*, 8 January 2013.

ElectraNet's initial proposal applied labour cost forecasts prepared by BIS Shrapnel.[100] ElectraNet did not use BIS Shrapnel for its revised proposal. Rather ElectraNet engaged KPMG for advice on its

100 ElectraNet, *Revenue proposal*, pp. 68–70.

labour cost outlook.[101] The KPMG forecast used the labour price index (LPI) as the basis and recommended:

- forecast growth for the electricity, gas and water (EGW) industry for internal labour,[102]
- forecast growth for the construction industry for external labour.[103]

ElectraNet engaged the Competition Economists Group (CEG) to update its materials inputs for its weighted average material escalator.[104] These material inputs were calculated in United States dollars ($US) and converted into Australian dollars ($AUD).

1.3 Assessment approach

We adopted the same assessment approach as our draft decision to assess ElectraNet's real cost escalation forecast. The following is a summary of our approach. For more details see section 1.3 of our draft decision.[105]

We assessed ElectraNet's revised proposed real cost escalators against the requirements in the NER. We must accept ElectraNet's opex and capex forecasts if satisfied the total forecasts reasonably reflect the opex and capex criteria.[106] To do this we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the opex and capex objectives.[107]

In making our draft decision for labour cost escalation, we:

- reviewed the KPMG reports commissioned by ElectraNet[108]
- considered advice from our commissioned consultant, DAE[109]
- tested the expert's forecasts against each other.

Where ElectraNet's revised proposal accepted our draft decision, we have updated the inputs to reflect most recent data.

We have also taken into consideration ECCSA's submission on this issue.[110]

1.4 Reasons for final decision

Our draft decision acknowledged there is no perfect predictor of escalators. Expert forecasters share this opinion.[111] Some forecasts are, however, likely to be more reliable than others. Consequently, we consider a range of material and views in reaching our conclusion. Based on our assessment, we are

101 KPMG, *Labour cost escalators*, January 2013 (Appendix D to ElectraNet's revised revenue proposal).
102 KPMG, *Labour cost escalators*, January 2013, p. 4.
103 KPMG, *Labour cost escalators*, January 2013, p. 5.
104 CEG, *Escalation factors affecting expenditure forecasts*, January 2013.
105 AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 57.
106 NER, clauses 6A.6.6(c) and 6A.6.7(c).
107 NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
108 KPMG, *Labour cost escalators*, January 2013 (Appendix D to ElectraNet's revised proposal), KPMG, *Independent examination of labour cost escalation modelling used by the AER in ElectraNet's 2012 draft decision*, January 2013 (Appendix C to ElectraNet's revised proposal).
109 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2012.
110 ECCSA, *ElectraNet SA Application: A response by the Energy Consumers Coalition of SA*, August 2012, p. 16.
111 Deloitte 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.

not satisfied that in all instances the forecasts proposed by ElectraNet satisfy the requirements of the rules.[112] In these instances we have substituted an alternative forecast.

1.4.1 Labour cost escalators

We do not accept that ElectraNet's revised proposed labour cost escalators reasonably reflect a realistic expectation of future labour costs. This is because the KPMG forecasts overstate ElectraNet's requirements for forecast labour costs for the 2013-18 regulatory control period. We also consider KPMG's assumptions in developing its EGW LPI forecast introduce an inherent level of forecasting error which makes it less reliable. In contrast, we consider DAE's forecast assumptions are more reasonable and better account for ElectraNet's requirements. Thus we have substituted DAE's labour cost forecasts as we consider they reasonably reflect a realistic expectation of the cost inputs ElectraNet requires to achieve the opex and capex objectives over the 2013–18 regulatory control period.

Adjusted versus unadjusted productivity forecasts

As noted in our draft decision, we also consider that in theory productivity adjustments apply to real cost escalations if productivity adjustments do not apply elsewhere in opex and capex forecasts.[113] However, because of the difficulty in estimating quality adjusted labour productivity estimates we do not have the ability to make this adjustment with an appropriate level of certainty.

We acknowledge ECCSA's considerations that productivity adjustments be applied to ElectraNet's forecast labour costs.[114] Thus while we expect worker productivity to improve over the long run, due to estimation difficulties, we have not sought to address this effect in ElectraNet's forecast of labour costs.

Review of expert forecasts

We reviewed the forecasts provided by DAE and KPMG. We note that although both experts have developed forecast labour cost escalators using LPI measures; the inputs, approaches and assumptions by the experts have differed. In determining which forecast will provide a realistic expectation of cost inputs given ElectraNet's circumstances for the 2013–18 regulatory control period we have reviewed the components of these forecasts below.

Availability of published labour price index data

Because of a lack of available published LPI industry data for South Australia, both DAE and KPMG made assumptions based on other available data in preparing their respective forecasts. While we have taken into consideration the data used to develop the respective forecasts, we have also considered the actual forecast method and assumptions in determining a reliable forecast.

We have previously noted our preference for labour cost forecasts based on publicly available data series published by the Australian Bureau of Statistics (ABS) because of its transparency. For internal labour cost forecasts we have preferred the use of the ABS EGWWS LPI data series and for external labour cost forecasts the ABS construction LPI data series. However, the ABS does not publish these industry data sets for South Australia.

[112] NER, clauses 6A.6.6(c)(3) and 6A.6.7(c)(3).
[113] AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 60.
[114] ECCSA, *ElectraNet SA application: A response by the Energy Consumers Coalition of SA*, February 2013, p. 12.

Consistent with our previous decisions, we consider the use of forecast growth in the EGWWS industry a good proxy for escalating an network service providers (NSP) internal labour costs. We consider it is a good reflection of all general internal labour and note that the ABS publishes this industry data series at the national level and often at the state level. The ABS has previously advised in regard to the EGWWS industry data series:[115]

> ...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.

We also consider the construction industry is a good proxy for escalating a NSP's external labour costs. The construction industry is a good reflection of the external contractor work a NSP requires.

We requested our technical consultant DAE to develop labour cost forecasts based on our above preferences. However, because this data is not directly available for South Australia, DAE was required to make assumptions based on other available data. We note ElectraNet requested KPMG's forecasts to be on a similar basis.[116] Consequently KPMG has also had to make assumptions.[117] Therefore in determining the reliability of these forecasts we must assess the assumptions applied by DAE and KPMG.

Forecast assumptions - Internal labour cost escalation

We do not accept ElectraNet's forecast internal labour cost escalators from 2015–16 to 2017–18. We consider the proposed escalators based on the KMPG's forecasts overstate ElectraNet's requirements for forecast internal labour costs over this period. In comparison, we consider DAE's forecast of LPI, unadjusted for productivity, for the South Australian EGWWS to be a more reliable forecast. Thus we have substituted DAE's forecast as we consider it reflects a realistic expectation of cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.

In our draft decision we accepted ElectraNet's enterprise agreement (EA) as the internal labour cost escalator to 2014–15.[118] Therefore our considerations on internal labour cost escalators for this final decision are for the period from 2015–16 to 2017–18 only.

For our final decision we have assessed both DAE's and KPMG's forecasts. We note that KPMG's analysis included both EGWWS and EGW LPI forecasts unadjusted for productivity. The EGW forecast is derived from KPMG's EGWWS forecast. That is KPMG initially developed its EGWWS forecast and then used ABS Census data to derive the EGW forecast from the EGWWS forecast. On the basis of its analysis KPMG concluded:[119]

> ElectraNet is an electricity transmission business and as such does not operate in waste water services and we therefore find that EGW is a more appropriate index than EGWWS to apply to the circumstances of ElectraNet.

Consequently, ElectraNet has applied KPMG's EGW forecast as its internal labour cost escalator from 2015–16 to 2017–18.

We acknowledge KPMG's recommendation for ElectraNet to use its EGW forecast. However, we consider that the reliability of the forecast should be a significant consideration when determining a forecast that reasonably reflects a realistic expectation of ElectraNet's internal labour costs for the

115 ABS, *Email from Kathryn Parlour to Fleur Gibbons*, 8 July 2010.
116 KPMG, *Labour cost escalators*, January 2013, pp. 4–5.
117 KPMG, *Labour cost escalators*, January 2013, pp. 6–12.
118 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 60–3.
119 KPMG, *Labour cost escalators*, January 2013, p. 5.

period 2015–16 to 2017–18.[120] As discussed in detail below, we do not consider KPMG's assumptions in developing its EGW LPI forecast from its EGWWS calculations using ABS Census data is reliable. We consider there is an inherent level of statistical error in undertaking KPMG's approach which makes it less reliable.

The economic assumptions underpinning KPMGs EGWWS forecast such as forecast expectations for competing labour are the same assumptions underpinning its EGW forecast. Therefore before we discuss KPMG's EGW forecast, our assessment of DAE's and KPMG's assumptions to develop their respective EGWWS forecasts are discussed below.

Assumptions to develop EGWWS LPI forecast

We consider ElectraNet would be over compensated for labour cost escalations if KPMG's EGWWS LPI forecast were applied. In contrast to KPMG's forecast, we consider DAE's EGWWS forecast has more reliably captured the environment in which ElectraNet will incur its labour costs over the 2015–16 to 2017–18 period.

Our draft decision accepted ElectraNet's EA as the internal labour cost escalator to 2014–15.[121] In determining whether the EA reasonably reflects a realistic expectation of forecast labour costs we considered a range of material. We noted that at the time ElectraNet entered into its current EA the expectation of competition for labour was high between other NSP's, the mining boom (including BHP's expansion of Olympic Dam mine) and other related industries. On the basis of this assessment we considered ElectraNet's EA was reasonable. However, our draft decision stated we would expect to see future collective wage agreements in South Australia to include lower wage growth than in previous years.

Over the medium term we consider there is some expectation of easing in the competition for labour compared with that experienced in recent years. There is some evidence that Australia's mining boom may be slowing leading to a weakened demand for labour.[122] Our draft decision noted that the multi–billion dollar BHP Olympic Dam mine expansion had been deferred indefinitely. BIS Shrapnel's forecast, adopted by ElectraNet in its initial revenue proposal, considered the Olympic Dam mine expansion would underpin growth and significantly lift investment and construction in South Australia.[123] Consequently, its indefinite deferral has somewhat reduced the competitive pressures on labour.

We also note there is a relatively modest outlook for investments in the South Australian utilities sector over the 2015–16 to 2017–18 period.[124] The utilities sector in recent times has been partially underpinned by a number of water projects including the $1.8 billion Port Stanvac desalination plant.[125] However, over the medium term these projects will end and there is a weaker outlook with a shift from water to a moderate level of electricity projects. The manufacturing industry in South Australia has also experienced a decline in employment demand due to the high Australian dollar

120 NER, clause 6A.6.6(c)(3).
121 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 60–3.
122 RBA, *Statement on monetary policy*, February 2013, p. 64–5.
123 BIS Shrapnel, *Labour cost escalation forecasts to 2017/18–Australia and South Australia*, April 2012, p. 11.
124 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p.81.
125 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 81.

affecting this industry.[126] Collective agreements for the other South Australian NSP's have annual wage increases trending downwards after experiencing historical highs.[127]

On this basis, we would expect to see some easing of ElectraNet's forecast labour cost compared to its current EA. This view is supported by KPMG who noted employment growth in an industry is a factor in wage increases.[128] It is also supported by DAE who stated:[129]

> As a result of the declining labour market pressures from mining and construction in the medium term, utilities wages should decline marginally relative to the overall rate, partially unwinding the relative strong increases seen over the past decade.

However, as table 1.3 demonstrates, KPMG is forecasting ElectraNet will encounter further upward pressures and incur historical high labour cost inputs towards the end of the 2013–18 regulatory control period.

Table 1.3 Comparison of DAE and KPMG South Australian EGWWS LPI forecasts (nominal, per cent)

	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18
ElectraNet–EBA	4.5	4.5	4.5			
KPMG–EGWWS	4.7	2.6	3.9	4.3	4.6	4.6
KPMG –EGW	5.1	4.8	4.3	4.6	4.9	4.9
DAE - EGWWS	4.3	3.2	2.9	3.2	3.3	3.5

Source: Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 80, KPMG, *Labour cost escalators*, January 2013, p. 17.

In relation to its forecast increase, KPMG stated:[130]

> From 2014–15, LPI for EGWWS in South Australia is accelerating, driven by activity in the sector growing at a faster pace than employment. In other words, productivity is rising and the wage sum is expanding faster than the number of employees in the industry.

While we accept that labour cost inputs are likely to increase over the forecast period, our assessment of ElectraNet's forecast labour costs uncovered little evidence to support KPMG's conclusion. Wage pressures in the South Australian utilities sector are more likely to level off if not decline in comparison with recent years. This consideration is supported by DAE who stated:[131]

> ... the recent run of strong EBA outcomes has lifted the growth of wages in all current EBAs well above the 4% level, meaning continued acceleration in wage gains is unlikely. That said, the wage momentum included in existing agreements is substantial, and goes some way to underpinning our expectation of a continuation of solid wage growth in the utilities though (sic) much of 2013–14.

On the basis of our assessment, we consider ElectraNet would be over compensated for labour cost escalations if KPMG's EGWWS LPI forecast were applied. In contrast to KPMG's forecast, we consider DAE's EGWWS forecast has more reliably captured the environment in which ElectraNet will

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126 BIS Shrapnel, *Labour cost escalation forecasts to 2017/18–Australia and South Australia*, April 2012, p. 12; Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 81.

127 EBA's from Fair Work Australia website: On 2 July 2007, APA Asset Management was appointed the major subcontractor to Envestra. The EBA's used in this analysis are therefore those of APA Asset Management. APA Network South Australia Agreement 2008; APA South Australia Network Agreement 2011; SA Power Networks was formerly known as ETSA Utilities, Utilities Management Pty Ltd Enterprise Agreement 2011.

128 KPMG, *Labour cost escalators*, January 2013, p. 9.

129 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p.84.

130 KPMG, *Labour cost escalators*, January 2013, p. 18.

131 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 84.

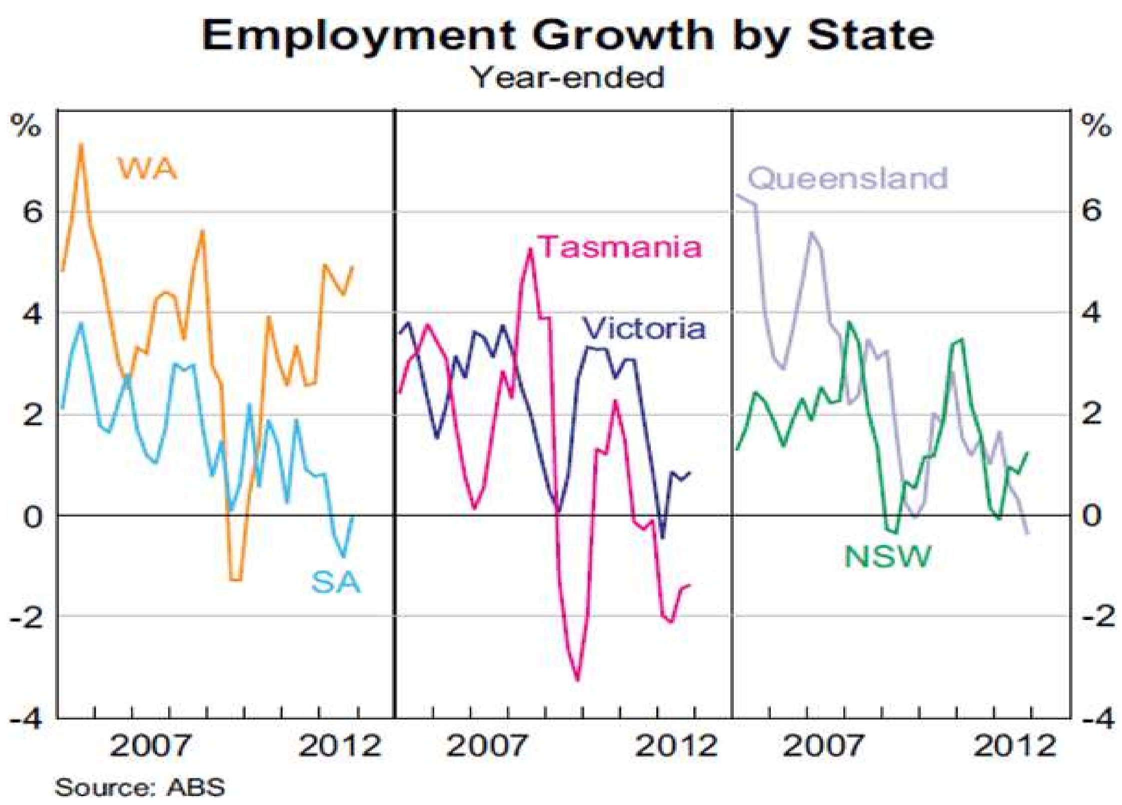
incur its labour costs over the 2015–16 to 2017–18 period. We consider DAE's forecast has more reliably taken into consideration the South Australian outlook for:[132]

- the competition for labour both before and after the peak of the mining boom
- the level of foreseeable utility sector investments and the shift in focus from water to power projects
- the issues of the 'two speed' economy and the effects of the manufacturing industry
- EA outcomes in both the short and medium term.

Assumptions to develop EGW LPI forecast

We consider there is an inherent level of statistical error in undertaking KPMG's assumption in developing its EGW LPI forecast which makes it less reliable. KPMG's method uses ABS Census employment data from Census 2006 and 2011 to develop its EGW forecast from its EGWWS forecast.[133] As the Census data is only published every five years it is questionable whether the data from these two points in time can form a reliable historical trend line which accurately reflects future circumstances. Although at a holistic level, figure 1.1 shows the volatility in employment growth from 2004 to 2012 taken from the Reserve Bank of Australia's statement on monetary policy.

Figure 1.1 RBA's employment growth by state[134]

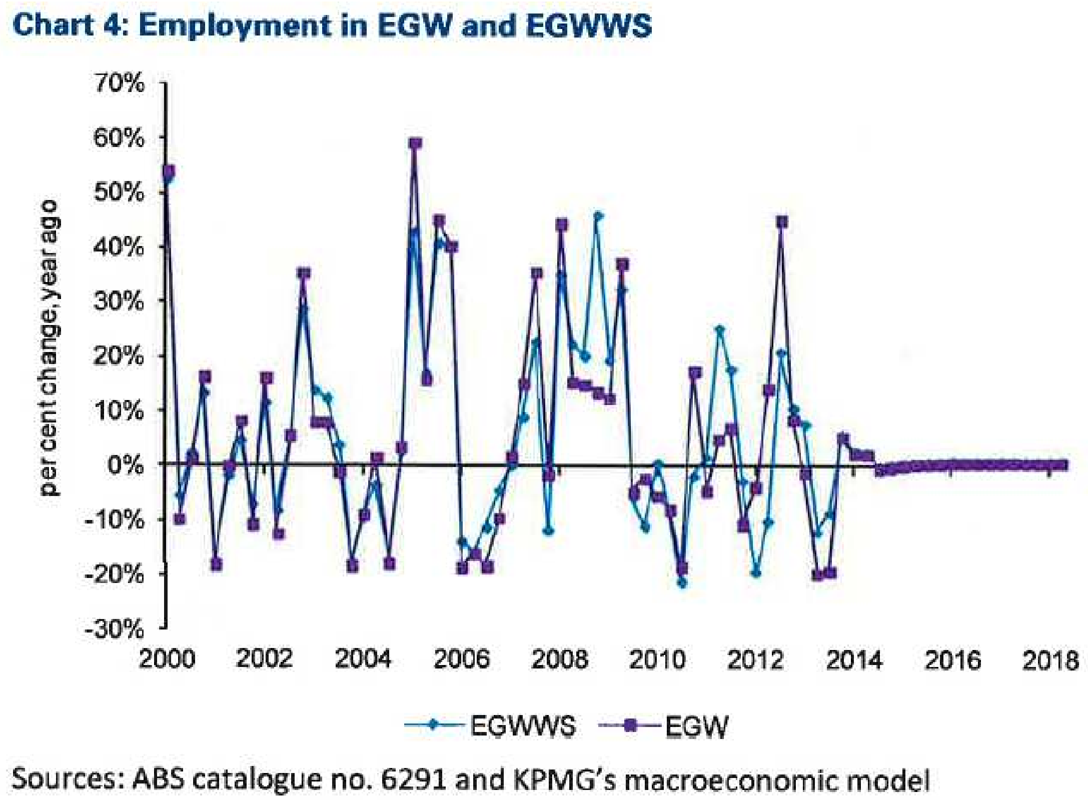


In addition, both KPMG and DAE's historical analysis of wage index movements demonstrate that wages can be volatile year on year.[135] Also, KPMG illustrated that South Australian EGW and

[132] Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, pp. 81–4.
[133] KPMG, *Labour cost escalators*, January 2013, pp. 10–1.
[134] RBA, *Statement on monetary policy*, February 2013, p. 39.

EGWWS employment is volatile with ebbs and flows year on year. As noted by KPMG employment levels affect labour costs.[136] Figure 1.2 is taken from KPMG's report which demonstrates this volatility in its historical and forecast analysis of employment in EGW and EGWWS.

Figure 1.2 Employment in EGW and EGWWS - KPMG analysis[137]



Therefore we consider that an average of the two data points is not sufficiently reliable in which to make projections about future labour costs. DAE agrees with this consideration and stated: [138]

> ...there would be no way of ascertaining whether the breakdown obtained from Census data at a point in time would necessarily still be applicable for subsequent years. Given the structural change occurring in the utilities sector there are good reasons to suspect they are not.

On balance, we consider that KPMG's assumptions in developing its EGW LPI forecast using ABS Census data introduces a level of forecasting error making it less reliable. Consequently we consider that KPMG's approach does not reasonably reflect a realistic expectation of the cost inputs ElectraNet requires to achieve the opex and capex objectives over the 2013–18 regulatory control period.

Further, our discussion above noted KPMG's EGW forecast is derived from its EGWWS forecast. Consequently the economic assumptions underpinning both forecasts are the same. For the reasons discussed above we considered KPMG's EGGWS assumptions are less reliable than those underpinning DAE's EGWWS forecast. Thus we also consider DAE's EGWWS assumptions are more reliable than KPMG's EGW assumptions.

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135 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia, 25 February 2013*, p. 98; KPMG, *Labour cost escalators*, January 2013, pp. 17 and 28.

136 KPMG, *Labour cost escalators*, January 2013, p. 9.

137 KPMG, *Labour cost escalators*, January 2013, p. 20.

138 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia, 25 February 2013*, p. 98.

External labour cost escalation

We accept ElectraNet's basis of using forecast LPI unadjusted for productivity in the construction sector for its external labour cost escalation. However, we do not accept ElectraNet's proposed escalators based on the KPMG forecasts. We consider KPMG and consequently ElectraNet has overstated its requirements for forecast external labour costs. In comparison, we consider DAE's forecast of LPI unadjusted for productivity for the South Australian construction industry to be an appropriate forecast. Thus we have substituted DAE's forecast as we consider it reflects a realistic expectation of cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.

Both DAE and KPMG consider there is evidence that the construction industry in South Australia will expand over the 2013–18 regulatory control period. However, we note there is a considerable divergence between the two forecasts.

DAE noted that housing construction activity in South Australia is low, engineering construction is still adjusting to the indefinite deferral of the multi–billion dollar expansion of Olympic Dam mine and commercial construction is being offset by weak demand in retail and office developments.[139] The latest gross state product (GSP) report from the South Australian Department of Treasury and Finance supports DAE's observations.[140] The report notes that the construction industry had the lowest growth rate (down 4 per cent) of all the gross value–added industries in South Australia. DAE stated that overall: [141]

> ...that combination points to a relatively weak construction sector in South Australia in the short term, with lagging population growth and poor leading indicators suggesting little hope of a rapid turnaround in housing construction, while both engineering and commercial construction have relatively modest pipelines given that South Australia's economy remains on the wrong side of the global pressures resulting from the high $A.

However, DAE also noted that there is some optimism of growth in the medium term.[142] It noted that the South Australian Government has boosted its First Home Owners Grant and a new grant for all buyers of newly constructed homes.[143] However, it considered the effects of these measures are likely to take a few years to gather momentum. It also noted that there were potential engineering and commercial construction projects that may go ahead and which would see wages perform relatively well compared to their national counterparts in the medium term.[144] Overall, DAE considered that:[145]

> ...South Australian construction wages are expected to rise in line with or marginally below the national equivalent.

This consideration appears to be shared by KPMG who stated:[146]

> The outlook for construction employment is cautiously optimistic. Employment has been contracting for four quarters but is projected to start improving thanks to a firmer economy, easier access to finance and lower interest rates.

However KPMG's forecast for South Australian construction LPI appears to be outperforming the national equivalent. We find this consideration overly optimistic given the modest foreseeable construction developments in South Australia. Table 1.4 presents DAE's and KPMG's

139 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, pp. 85-86.
140 Department of Treasury and Finance (SA), *Gross state product, 2011–12*, 21 November 2012.
141 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 85.
142 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 86.
143 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 85.
144 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 86.
145 Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 86.
146 KPMG, *Labour cost escalators*, January 2013, p. 9.

South Australian construction LPI forecasts against the national equivalent historical average from 1998 to 2012.

Table 1.4 Comparison of DAE and KPMG South Australian construction LPI forecasts (nominal, per cent)

	Historical average	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18
DAE–South Australia		3.5	3.4	3.4	3.1	2.8	3.2
KPMG–South Australia		5.0	4.9	6.2	5.5	5.0	5.0
ABS–National	4.0						

Source: Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 80, KPMG, *Labour cost escalators*, January 2013, p. 29, ABS, cat. No. 64345.0.

KPMG considered that GSP and CPI are some of the drivers for the increase in its South Australian construction LPI forecast.[147] However it considered the key driver is compensation of employees which it noted is closely connected to industry output.[148] KPMG stated:[149]

> Firm performance in the construction sector is pushing demand for construction labour higher and the industry's LPI rises.

KPMG also stated:[150]

> If an industry is expanding, upward wage pressures emerge if labour is not readily available and the LPI will edge higher.

Given these considerations we would expect that, like the LPI, these upward pressures would be reflected in current enterprise bargaining agreements (EBA). However, DAE noted the information produced by the Department of Education, Employment and Workplace Relations demonstrates that South Australian local construction sector EBA's have contracted recently in comparison to prior years.[151] Given KPMG's statements, although noting relatively few workers in the construction sector are covered by EBA's, this would demonstrate a cooling off in demand for construction labour and not the upward pressures it claims.

On balance we consider there is evidence that the construction industry in South Australia will expand over the 2013–18 regulatory control period. However, given the reasoning above, we consider ElectraNet's proposed escalators based on the KPMG forecasts overstate this expansion. In comparison, we consider DAE's forecast of LPI unadjusted for productivity for the South Australian construction industry to be an appropriate forecast. Thus we have substituted DAE's forecast as we consider it reflects a realistic expectation of cost inputs required to achieve the opex and capex objectives over the 2013–18 regulatory control period.

1.4.2 Material escalators

We have applied ElectraNet's proposed weighted average material escalation method for our final decision and updated the inputs to reflect the latest available data and conversion rates. We accepted this method in our draft decision as being reasonable. We consider the update of data and conversion

[147] KPMG, *Labour cost escalators*, January 2013, p. 29.
[148] KPMG, *Labour cost escalators*, January 2013, p. 29.
[149] KPMG, *Labour cost escalators*, January 2013, p. 29.
[150] KPMG, *Labour cost escalators*, January 2013, p. 9.
[151] Deloitte Access Economics, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 87.

rates reflects a realistic expectation of the cost inputs required to achieve the capex objectives.[152] Table 1.5 shows ElectraNet's revised proposal and our final decision on the real weighted average material escalation. Table 1.6 shows the respective conversion rates.

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

Annual escalation	2013–14	2014–15	2015–16	2016–17	2017–18
ElectraNet revised proposal	2.1	2.3	1.8	1.8	1.7
AER final decision	2.1	1.8	0.4	0.3	0.6

Source: AER analysis, ElectraNet, *Revised capex model*, 8 February 2013.

ElectraNet's revised proposal applied the same method we accepted in our draft decision and updated its inputs based on the latest advice from its consultant CEG.[153] We have updated these inputs for our final decision given that CEG's report was prepared in January and more recent forecasts are available.

Table 1.6 US dollar to Australian dollar exchange rate forecast

$AUD–$US exchange rate	2013–14	2014–15	2015–16	2016–17	2017–18
ElectraNet revised proposal	1.01	0.99	0.96	0.93	0.91
AER final decision	1.01	0.98	0.96	0.93	0.91

Source: AER analysis, CEG, *Escalation factors affecting expenditure forecasts*, January 2013, pp. 11–2.

1.4.3 Land value escalators

We accept ElectraNet's revised revenue proposal application of our draft decision land value escalator inputs and assumptions. We consider our draft decision application of land value escalators reasonably reflects a realistic expectation of the cost inputs ElectraNet requires to achieve the opex and capex objectives over the 2013–18 regulatory control period.[154] Table 1.7 shows the final decision land value escalators.

152 NER, clauses 6A.6.7(c)(3) and 6A.6.7(1).
153 ElectraNet, *Revised revenue proposal*, p. 17, CEG, *Escalation factors affecting expenditure forecasts*, January 2013 (Appendix E to ElectraNet's revised revenue proposal).
154 NER, clauses 6A.6.6(c).

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

Land value index	AER final decision Average annual increase (June 1989—June 2011)
Residential land	8.1
Commercial land	5.4
Rural land	4.9
Other land	5.9
Total land	6.9

Source: AER analysis; ABS, *5204 Australian System of National accounts publication 2010–11*.

ElectraNet's revised proposal stated it reflected our draft decision's land value escalation inputs and assumptions.[155] However, the capex model submitted with ElectraNet's revised proposal did not apply our draft decision outcomes.[156] Consequently we asked ElectraNet to explain this discrepancy.[157] ElectraNet explained this was an oversight and subsequently provided us with an updated capex model to reflect this.[158]

However, we have found that ElectraNet's latest capex model applied the incorrect land value escalator for the first year of escalation for two proposed land and easement projects. We have corrected this for our final decision.

1.5 AER decision

Decision 1.1: Table 1.1 sets out our substitute real cost escalators for the 2013–18 regulatory control period.

155 ElectraNet, *Revised revenue proposal*, p. 18.
156 ElectraNet, *Revised capex model*, January 2013.
157 AER, *Information request AER RRP 001 - Questions relating to the capex model*, 30 January 2013.
158 ElectraNet, *Revised capex model*, 8 February 2013.

2 Capital expenditure

This attachment outlines our final decision, reasoning and approach to assessing ElectraNet's revised proposed capital expenditure (capex) and for deriving our substitute forecast for the 2013–18 regulatory control period.

2.1 Final decision

We do not accept ElectraNet's revised proposed total forecast capex of $750.1 million ($2012–13) for the 2013–18 regulatory control period.[159] We are not satisfied the revised forecast reasonably reflects the capex criteria because we consider ElectraNet has overstated elements of the forecast.[160] We have thus estimated a substitute total forecast capex that reasonably reflects the NER requirements and our final decision demand forecast.[161] We have made adjustments to the following components of ElectraNet's revised forecast capex to develop our substitute forecast as required under the NER:[162]

- cost estimation risk factor and prudency adjustment—$38.2 million ($2012–13) reduction
- capex/opex trade off—$5.5 million ($2012–13) reduction
- real cost escalation—$6.0 million ($2012–13) reduction
- strategic land and easement acquisitions—$10.7 million ($2012–13) reduction.

Table 2.1 summarises the substitute total forecast capex we consider ElectraNet requires over the 2013–18 regulatory control period. We have estimated a total forecast capex of $690.7 million ($2012–13), which represents a reduction of $59.5 million ($2012–13) (or 7.9 per cent) on ElectraNet's revised revenue proposal.

159 NER, clause 6A.14.1(2)(ii).
160 NER, clause 6A.6.7(c).
161 NER, clause 6A.14.1(2)(ii).
162 NER, clause 6A.14.1(2)(ii).

Table 2.1 Final decision on ElectraNet's total forecast capex ($ million, 2012–13)

	Incremental adjustment	Aggregate adjustment	Total capex
ElectraNet forecast capex			**750.1**
Cost estimation risk factor		**–15.4**	
0% replacement/refurbishment	–13.4		
2.6% all other relevant capex	–2.0		
Prudency		**–38.2**	
Replacement/refurbishment	–23.8		
Capex/opex trade off		**–43.3**	
Replacement/refurbishment	–5.5		
Real cost escalators	–6.0	**–48.8**	
Land and easements	–10.7	**–59.5**	
AER's final decision forecast capex			**690.7**

Source: AER analysis, EMCa analysis. The sum of incremental adjustments is greater than the total aggregate adjustment as the incremental adjustments reflect standalone adjustments to ElectraNet's revised proposal.

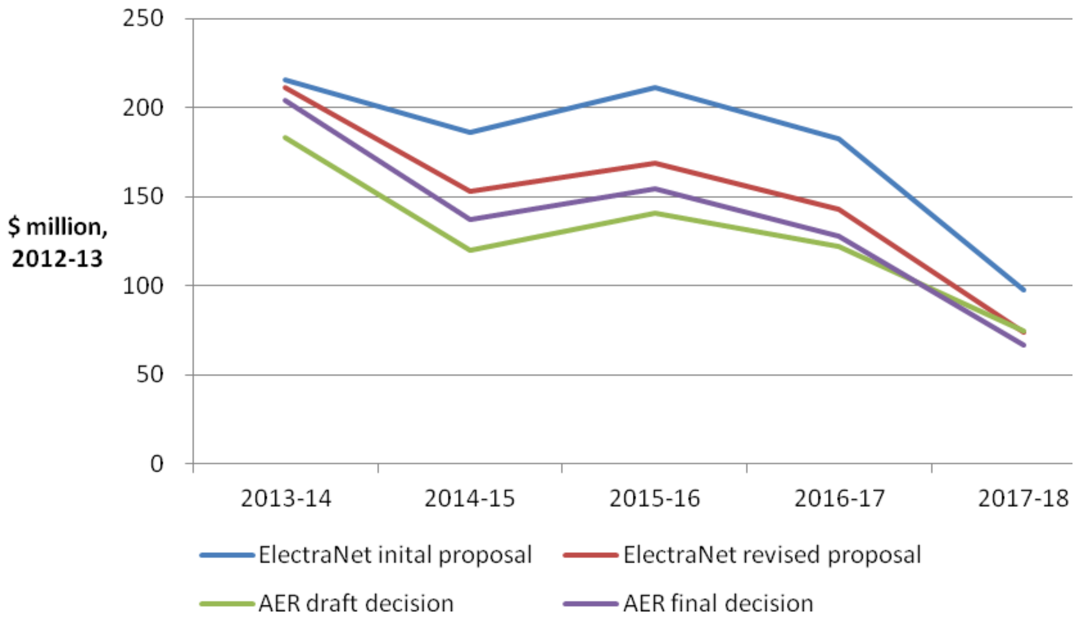
Table 2.2 shows our final decision in more detail.

Table 2.2 AER final decision on ElectraNet's total forecast capex–by category ($ million, 2012–13)

Capex category	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Augmentation	38.0	11.4	10.7	12.4	14.5	87.1
Connection	38.9	17.2	17.2	10.0	3.6	86.9
Replacement	80.3	60.4	63.6	69.9	30.6	304.9
Refurbishment	1.0	5.4	25.5	12.5	1.7	46.1
Strategic land /easements	11.3	13.2	5.1	1.1	0.0	30.7
Security /compliance	17.8	13.9	14.3	10.8	8.1	64.9
Inventory /spares	5.3	3.7	4.6	3.0	2.1	18.6
Total network	**192.7**	**125.2**	**141.0**	**119.9**	**60.6**	**639.3**
Business IT	10.9	10.8	11.4	7.2	5.5	45.8
Building /facilities	0.7	1.5	2.1	0.6	0.6	5.6
Total non–network	**11.6**	**12.2**	**13.6**	**7.9**	**6.1**	**51.3**
Total forecast capex	**204.2**	**137.5**	**154.5**	**127.7**	**66.7**	**690.7**

Source: AER analysis. Note these figures are "as incurred". Numbers may not add due to rounding.

Figure 2.1 ElectraNet initial and revised proposed and the AER's draft and final substitute total forecast capex allowances ($ million, 2012–13)



Source: ElectraNet, *Revenue proposal*, p. 76; ElectraNet, *Revised capex model,* 8 February 2013; AER, *Draft decision, ElectraNet transmission determination*, November 2012, pp. 112; AER analysis.

2.2 ElectraNet's revised proposal

ElectraNet's revised revenue proposal contained a total forecast capex of $750.1 million ($2012–13) (table 2.3) down $144.0 million ($2012–13) (or 16.1 per cent) on its initial revenue proposal.[163] The major differences between ElectraNet's initial and revised capex proposal are:

- lower augmentation and connection capex due to its revised demand forecast
- revised land and easement projects.

163 ElectraNet's revised proposal presented a total forecast capex of $748.3 million ($2012–13) due to an inadvertent error in its land and easement escalators. Consequently, ElectraNet provided an updated total forecast of $750.1 million ($2012-13) correcting for this error.

Table 2.3 ElectraNet's revised revenue proposal, initial revenue proposal and AER draft decision total forecast capex by category ($ million, 2012–13)

Capex category	2013–14	2014–15	2015–16	2016–17	2017–18	Revised proposal	Initial proposal	Draft decision
Augmentation	38.0	11.4	10.7	12.7	15.3	88.3	117.9	98.7
Connection	39.0	17.4	17.8	10.6	3.8	88.5	133.2	101.7
Replacement	86.0	66.6	71.9	81.6	36.7	342.8	398.0	261.6
Refurbishment	1.1	6.2	29.5	14.7	2.1	53.6	54.2	42.2
Strategic land /easements	12.5	21.2	6.1	1.5	0.0	41.4	65.8	13.4
Security /compliance	17.8	13.9	14.5	10.9	8.1	65.3	57.3	56.9
Inventory /spares	5.3	3.8	4.7	3.0	2.1	18.9	18.4	18.0
Total network	**199.8**	**140.6**	**155.3**	**135.0**	**68.1**	**698.8**	**844.9**	**592.6**
Business IT	10.9	10.8	11.4	7.2	5.5	45.8	43.7	43.7
Building /facilities	0.7	1.5	2.1	0.6	0.6	5.6	5.4	5.4
Total non–network	**11.6**	**12.2**	**13.6**	**7.9**	**6.1**	**51.3**	**49.3**	**49.3**
Total forecast capex	**211.4**	**152.8**	**168.9**	**142.9**	**74.2**	**750.1**	**894.1**	**641.9**

Source: ElectraNet, *Revised capex model,* 8 February 2013, ElectraNet, *Revenue proposal*, p. 76, AER, *Draft decision, ElectraNet transmission determination*, November 2012, pp. 112*.*

ElectraNet's revised revenue proposal did not accept our draft decision outcomes on:[164]

- cost estimation risk factor
- prudency adjustment to replacement and refurbishment projects
- capex/opex trade off
- strategic land and easements
- load driven projects.

In response to our draft decision, ElectraNet's revised revenue proposal included a lower demand forecast than originally proposed. As a consequence its revised augmentation and connection capex forecast was also lower than originally proposed. In revising its demand forecast, ElectraNet also:

- commented on its obligations under the South Australian Electricity Transmission Code (ETC) and their application to this regulatory determination; and
- proposed a cost pass through event.

2.3 Assessment approach

We adopted the same approach as our draft decision to assess ElectraNet's revised capex forecast. The following is summary of our approach. For more details see section 4.3 of our draft decision.[165]

[164] ElectraNet, *Revised revenue proposal*, p. 49.

We must either accept ElectraNet's proposed forecast capex allowance or determine a substitute forecast.[166] We must accept ElectraNet's proposed forecast capex if satisfied it reasonably reflects the capex criteria.[167] 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 (capex criteria).[168] In deciding whether ElectraNet's proposed forecast capex reasonably reflects the capex criteria, we must have regard to the capex factors.[169] Although we considered each capex factor when assessing ElectraNet's proposed total forecast capex, not all factors were relevant to each capex component.[170]

In our assessment we also had regard to the National Electricity Objective (NEO) as well as the revenue and pricing principles in the National Electricity Law (NEL).[171]

We must form a view on the forecast capex as a whole, not as individual projects or programs.[172] However, because the total required capex is separated into expenditure components, we assess these components to make our decision on the total amount.

In assessing ElectraNet's efficient costs, we considered a mix of top down and bottom up approaches. We again engaged Energy Market Consulting associates (EMCa) to help review ElectraNet's forecast capex.

We also considered the issues raised in submissions.[173]

A summary of our understanding of the effect of the ETC on ElectraNet's revised proposal is also included in our reasons for final decision. ElectraNet's proposed cost pass through event is considered in appendix 13 of this decision.

2.4 Reasons for final decision

Overall, we do not accept that ElectraNet's revised proposed total forecast capex satisfies the requirements of the NER and NEO for the reasons outlined in this section.[174] We consider ElectraNet's revised proposed forecast does not meet the capex criteria.[175] That is, ElectraNet has in a sense taken an ‘overly cautious’ approach to developing an efficient and prudent capex forecast. It has not sufficiently accounted for its own actions on continuous improvement.

ElectraNet's revised land and easement capex is also overstated because it has not sufficiently taken into account relevant factors that drive an efficient and prudent expenditure forecast. Thus we have

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165 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 114-5.
166 NER, clauses 6A.6.7(c) and (d).
167 NER, clause 6A.6.7(c).
168 NER, clause 6A.6.7(c). Clause 6A.6.7(a) specifies the capex objectives.
169 NER, clause 6A.6.7(d).
170 ElectraNet's capex forecast recovery is 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.
171 NEL, s.7 and s.7A.
172 NER, clause 6A.14.1(2).
173 Centrex Metals, *Submission to AER draft decision and ElectraNet 2013–18 revised revenue proposal*, 19 February 2013; ECCSA, *ElectraNet SA Application: A response by The energy consumers coalition of SA*, February 2013; EUAA, *Submission to the AER on Electranet revenue draft determination 2013/14 to 2017/18*, February 2013; Iron Road Ltd, *ElectraNet revenue proposal: Iron Road Limited submission to Australian Energy Regulator*, 18 February 2013; SA Govt, *Support for (ElectraNet) Eyre Peninsula line upgrade*, 26 February 2013; Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, 18 February 2013; Transgrid, *ElectraNet draft decision and revised revenue proposal 2013–2018*, February 2013.
174 NER, clauses 6A.14.1(2)(ii) and 6A.6.7(c); NEL, ss. 7 and 7A.
175 NER, clause 6A.6.7(c).

made adjustments to the following components of ElectraNet's capex forecast to develop a substitute forecast as required by the NER:[176]

- cost estimation risk factor and prudency adjustment
- capex/opex trade off
- real cost escalation
- strategic land and easement acquisitions.

Our detailed reasons are discussed below.

2.4.1 Asset management framework

We focused our assessment on how ElectraNet's revised forecast capex reflects its asset management framework. In our draft decision, we considered ElectraNet's asset management framework is consistent with good industry practice but questioned its implementation.[177] In our assessment of ElectraNet's revised capex proposal, we again investigated whether ElectraNet has sufficiently accounted for its own actions on continuous improvements. Based on our assessment, we maintain our draft decision findings. Consequently our final decision substitutes an allowance that we consider accounts for ElectraNet's actions on continuous improvements.

Our draft decision concluded that ElectraNet had not sufficiently accounted for its own actions on continuous improvement. Consequently we adjusted ElectraNet's forecast capex through the cost estimation risk factor, capex/opex trade off and applied a prudency adjustment. This resulted in a lower capex forecast consistent with ElectraNet's asset management framework and good industry practice on capital governance.

2.4.2 Cost estimation risk factor and prudency adjustment

We do not accept ElectraNet's revised proposal cost estimation risk factor of 4.9 per cent. We also do not accept ElectraNet's revised proposal as it did not adopt the prudency adjustment we specified in our draft decision. The prudency adjustment reduces ElectraNet's proposed replacement and refurbishment capex by 7 per cent. We consider that our draft decision forecast capex is prudent and efficient.[178] Our final decision is to apply our draft decision on the cost estimation risk factor and prudency adjustment as we consider it accounts for ElectraNet's actions on continuous improvement. Table 2.4 sets out the impact of our final decision on ElectraNet's proposed forecast capex. Overall, ElectraNet's proposed forecast capex reduces by $38.2 million ($2012–13) due to these adjustments.

176 NER, clauses 6A.14.1(2)(ii) and 6A.6.7(c); NEL, ss. 7 and 7A.
177 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 98-108.
178 NER, clause 6A.6.7(c).

Table 2.4 AER's final decision on cost estimation risk factors and prudency adjustment ($ million, 2012–13)

Cost estimation risk factors and prudency adjustment	$ million
0 per cent — cost estimation risk factor — replacement and refurbishment capex	–13.4
2.6 per cent — cost estimation risk factor — all other relevant network capex	–2.0
7.0 per cent — prudency adjustment — replacement and refurbishment capex	–23.8
Total	**–38.2**

Source: AER analysis, EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 47–58.

Cost estimation risk factor

We do not accept ElectraNet's revised proposal cost estimation risk factor of 4.9 per cent. On the basis of our analysis we consider ElectraNet's proposed cost estimation risk factor overstates its capex requirement for the 2013–18 regulatory control period. Overall we consider the Evans & Peck analysis ElectraNet used to derive its proposed cost estimation risk factor to be insufficiently transparent and thus unable to support robust conclusions.

Based on our assessment of the Evans & Peck analysis and ElectraNet's actual historical outcomes we consider our substitute cost estimation risk factors presented in table 2.5 account for ElectraNet's actions on continuous improvement. We also consider these adjustments reasonably reflect the efficient and prudent costs of maintaining the quality, reliability and security of supply of ElectraNet's prescribed transmission services.[179]

Table 2.5 ElectraNet's revised proposal and AER's final decision on cost estimation risk factors (per cent)

Cost estimation risk factors	Per cent
ElectraNet — cost estimation risk factor — portfolio	4.9
AER — cost estimation risk factor — replacement and refurbishment capex	0
AER — cost estimation risk factor — all other relevant network capex	2.6

Source: ElectraNet, *Revised revenue proposal*, p. 52, AER analysis, EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 58.

The cost estimation risk factor is applied to concept stage capital projects that are yet to undergo a detailed cost build-up.[180] The objective of this factor is to account for an asymmetric risk that unforseen factors will lead to actual project costs to exceed initial cost estimates across a portfolio of projects. It is only applied to forecast network projects that present an element of cost estimation risk such as replacement, refurbishment, connection and augmentation capex. It excludes projects such as land and easement acquisitions and information technology. ElectraNet's initial proposal contained a cost estimation risk factor of 4.9 per cent. Our draft decision considered ElectraNet had overstated

179 NER, clauses 6A.6.7(a)(3), (c)(1) and (2).
180 ElectraNet, *Revenue proposal*, pp. 67-68.

the level of asymmetric risk it could be exposed to in the 2013–18 regulatory control period. Consequently we substituted a cost estimation risk factor of 0 per cent for replacement and refurbishment capex and 2.6 per cent for all other relevant network capex.[181]

ElectraNet's revised revenue proposal did not adopt the cost estimation risk factors set out in our draft decision.[182] ElectraNet stated the evidence did not support the basis for our draft decision and reverted back to Evans & Peck's findings of 4.9 per cent.[183] ElectraNet's main criticism was that we had not based our conclusions on empirical evidence. It considered:[184]

> Historical analysis (especially when reinforced through scientific methods) of project cost data is the best method for determining an appropriate cost estimation risk allowance.

It also noted that experience and accepted practice shows brownfield projects (replacement capex) as risky as greenfield projects.[185]

In light of ElectraNet's focus on past outcomes and the weight it places on Evans & Peck's analysis, we have again reviewed the past outcomes and the Evans & Peck report in detail.[186] Our findings are:

- On a portfolio basis, actual capex was about 5 per cent lower than ElectraNet proposed. Actual replacement costs were about 16 per cent lower than proposed.
- Evans and Peck has overcomplicated the analysis and in the process has not produced a meaningful case to support a 4.9 per cent cost estimation risk factor.

We discuss these findings in more detail below.

Actual past cost outcomes

We have undertaken analysis of ElectraNet's actual past outcomes against its estimated forecast expenditure for this final decision. We consider in some instances ElectraNet's actual past cost outcomes may not be a good predictor of future outcomes. This is because ElectraNet's past performances do not fully reflect its actions on continuous improvements which will be reflected in future outcomes. However, given that ElectraNet and other stakeholders consider that some weight be applied to ElectraNet's past cost outcomes we have undertaken this analysis for our final decision.[187]

Our analysis assessed the difference between ElectraNet's past actual outcomes against its estimated expenditure over the 2008–13 regulatory control period. This assessment analysed the difference at the portfolio level and at the combined category levels of augmentation and connection capex as well as replacement capex.[188] We engaged our technical consultant EMCa to undertake this analysis on our behalf.[189] EMCa's complete method is set out in its report. In summary EMCa:[190]

- used data available from both ElectraNet's 2008–13 revenue proposal and data provided by ElectraNet

181 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 122–4.
182 ElectraNet, *Revised revenue proposal*, pp. 48–52, 54.
183 ElectraNet, *Revised revenue proposal*, p. 52.
184 ElectraNet, *Revised revenue proposal*, p. 52.
185 ElectraNet, *Revised revenue proposal*, pp. 50–1.
186 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 50–8, paragraphs 198–248.
187 ElectraNet, *Revised revenue proposal*, p. 52; Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, 18 February 2013, p. 4, Transgrid, *ElectraNet draft decision and revised revenue proposal 2013–2018*, February 2013, p. 3.
188 ElectraNet did not report refurbishment capex in the 2008–13 regulatory control period.
189 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 55–8, paragraphs 235–248.
190 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 55–6, paragraphs 236–237.

- analysed projects proposed for the 2008–13 regulatory control period only
- converted all proposed and actual costs to $2012–13
- included all relevant data points (projects were excluded where either projected and/or actual costs could not be identified)
- treated projects as a single project if it had been proposed in separate components (e.g. augmentation and replacement)
- assessed the difference between project concept estimates and actual costs incurred.

Table 2.6 presents the outcomes of this analysis.

Table 2.6 Analysis of estimated versus actual project costs in the current regulatory control period

	Portfolio (all projects)	Augmentation and connection projects	Replacement projects
Number of projects	44	23	12
Total value ($m as proposed)	598	347	141
Total cost ($m as incurred)	567	352	122
Mean % project overspend/underspend	–5%	1%	–14%

Source: EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 56.

This analysis demonstrates that at the portfolio level ElectraNet incurred actual costs approximately five per cent below that of its estimates. It also demonstrates that actual augmentation and connection capex project costs are about one per cent above estimates while replacement projects come in significantly under estimated levels. The outcome of this analysis is different to that proposed by ElectraNet in both its initial and revised regulatory proposals particularly in relation to its proposed 4.9 per cent cost estimation risk factor. The outcome also supports EUAA's consideration that ElectraNet not be provided with an allowance for cost estimation risk.[191]

EMCa noted these results were similar to analysis performed by it on two other electricity transmission utilities.[192] That is, actual costs were less than estimates across the portfolio and there were even greater under-spends for replacement and refurbishment projects than augmentation and connection projects.

To determine the reasonableness of this analysis, EMCa engaged technical expert MetService to undertake additional statistical analysis.[193] The analysis was undertaken using two separate modelling approaches—Non-parametric bootstrap and Bayesian. While the two modelling approaches produced differing value outcomes, the outcomes from both were similar to EMCa's findings. Table 2.7 presents the outcomes of this analysis.

191 EUAA, *Submission to the AER on Electranet revenue draft determination 2013/14 to 2017/18*, February 2013, p. 19.
192 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 57, paragraph 244.
193 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 56, paragraph 238.

Table 2.7 Mean outcomes of MetService analysis of estimated versus actual project costs in the current regulatory control period (per cent)

	Portfolio (all projects)	Augmentation and connection projects	Replacement projects
Non-parametric bootstrap	–5%	3%	–16%
Bayesian	–7%	0%	–16%

Source: EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 56., MetService, *Project budget estimation analysis*, 17 February 2013.

This analysis demonstrates that on a portfolio basis ElectraNet's completed project costs are between 5 and 7 per cent less than initial estimates.[194] Further, the analysis shows that replacement and refurbishment projects incurred actual costs at an aggregate 16 per cent lower than estimated costs. However, augmentation and connection capex projects are between estimated cost and a 3 per cent overspend of estimate.

Due to the small sample size of data, weight was given to the confidence intervals for the outcomes produced by the models.[195] Based on the confidence intervals, EMCa drew the following conclusions:[196]

- Applying a positive "portfolio risk factor" of 4.9 per cent to the "all projects" portfolio budget is not justified;
- On the balance of probability, it is more likely that "all projects" and "replacement" projects will under–spend rather than over–spend, that "replacement and refurbishment" projects will under–spend more than "all projects" and also that "replacement and refurbishment" projects will under–spend by more than "augmentation and connection" projects.
- Taking into account the combined effects of portfolio risk and prudency, there is not a case for applying any positive risk factor to the aggregate portfolio budget although there may be a case to apply a small aggregate positive adjustment to the augmentation and connection projects, along with a negative adjustment to replacement and refurbishment projects.

As this detailed analysis was undertaken after our draft decision, we provided ElectraNet with our analysis and findings prior to our final decision.

ElectraNet's response noted our small sample size of data.[197] However, we consider our analysis has taken into consideration all projects proposed by ElectraNet which are now completed or substantially completed within the 2008–13 regulatory control period.[198] We note our analysis is not selective but rather focussed on a dataset in which reliable considerations can be made.[199] EMCa's considerations of ElectraNet's response noted:[200]

> ElectraNet has confirmed, as we observed from our inspection of the Evans & Peck data, that the dataset that ElectraNet provided to Evans & Peck included a number of projects that were not in fact complete but rather were at "an advanced stage in the approval process". We have noted that the dataset ElectraNet provided to Evans & Peck is different from the complete dataset that we have used and comprises only 29 completed projects, augmented by a further 30 projects which we assume to be those for which ElectraNet provided current estimates as "actual costs" based on them being "at an advanced stage in the approval process".

194 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 56, paragraph 239.
195 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 54–6, paragraph 234.
196 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 56–7, paragraph 241.
197 ElectraNet, *Email response to information request AER RRP 17, CERF and prudency adjustment*, March 2013.
198 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 120, paragraph 448.
199 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 120, paragraph 448.
200 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 120, paragraph 448.

EMCa further noted that the number of observations in its analysis is not materially different from the size of the dataset ElectraNet provided to Evans & Peck.[201] However, unlike the Evans & Peck analysis we have given weight to the confidence intervals to provide further substance to the small sample size of data.[202]

ElectraNet's response also considered that our analysis covers a broader observation of cost variation than just cost estimation risk and contained some issues regarding the data we used.[203] It also considered our analysis had not taken into account the improvements in its cost estimation processes.[204]

We agree with ElectraNet that our analysis covers a broader consideration than just the cost estimation risk factor.[205] We note that ElectraNet has not provided evidence to indicate that improvements in its cost estimation accuracy are the driver for our analysis findings that historical outcomes were lower than forecasts. We also acknowledge ElectraNet's comments on data issues but note EMCa's response that ElectraNet's and Evans & Peck responses, in fact, supports the conclusions reached by EMCa.[206]

While we have been able to draw conclusions from our analysis on the cost estimation risk factor, our analysis has also informed our considerations on the application of the prudency adjustment for our final decision. Our considerations on the prudency adjustment are discussed in detail below

On the basis of our analysis, we consider ElectraNet's proposal is overstated particularly in relation to its cost estimation risk factor. Nevertheless, we also assessed Evans & Peck's findings.

Evans & Peck analysis

Evans & Peck reported that it developed ElectraNet's cost estimation risk factor based on historical data and derived a 4.9 per cent factor at the portfolio level.[207] Our analysis finds that Evans & Peck's findings have the following weaknesses:

- insufficient evidence that its "P50" cost assumption is valid
- data set not reflective of forecast portfolio projects
- multiple layers of data manipulation overcomplicating the analysis
- lack of confidence intervals to demonstrate the statistical significance.

We consider ElectraNet has provided us with insufficient evidence to conclude that the "P50" value assumption Evans & Peck used in its analysis is valid. We note that Evans & Peck analysis relies on base planning object (BPO) cost data provided by ElectraNet on a 'good faith' basis.[208] Its analysis of this data applies the assumption that the BPO costs fit a "P50" cost estimate. That is, it assumes the expenditure profile has a 50 per cent probability of cost over-run and 50 per cent probability of cost under–run. However, in our analysis we have not been able to conclude with certainty that the BPO costs are exclusive of asymmetric risk and that the "P50" assumption is valid. We note EMCa requested ElectraNet to demonstrate how the asymmetric risk component of the BPO was

201 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 120, paragraph 448.
202 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 120, paragraph 448.
203 ElectraNet, *Email response to information request AER RRP 17, CERF and prudency adjustment*, March 2013.
204 ElectraNet, *Email response to information request AER RRP 17, CERF and prudency adjustment*, March 2013.
205 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 55, paragraph 235.
206 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 119–121, paragraphs 448–449.
207 Evans & Peck*, ElectraNet capital program estimating risk analysis*, May 2012.
208 Evans & Peck*, ElectraNet capital program estimating risk analysis*, May 2012, p. 4.

removed.[209] EMCa noted that ElectraNet provided no explanation of how or whether this was done. Based on their experience and investigations into ElectraNet's BPO's, EMCa concluded:[210]

> ...it is difficult to avoid the conclusion that the BPO costs inherently include the effects of asymmetric cost over–runs, since they are based on actual project costs which included such over–runs to the extent that they occurred in practice.

In relation to the data set Evans & Peck used, we cannot conclude that the projects included in the data set reflect the portfolio of projects to be undertaken by ElectraNet over the 2013–18 regulatory control period. Our review of the data used by Evans & Peck demonstrates that of the 29 projects that have actual costs to compare with estimates, only three are labelled as augmentation and connection projects and only four are labelled as replacement projects.[211] The remainder are labelled as security/compliance or are uncategorised.[212] Thus, we question the reliability of these projects reflecting a forecast portfolio of costs largely made up of replacement projects. We also note the Evans & Peck analysis also relied on another 32 projects which do not have final costs but were considered as being final.

We also question the reliability of the Evans & Peck analysis due to the multiple manipulations of the data and its lack of statistical significance evidence. We note Evans & Peck's analysis encountered the same small number of data points as our analysis.[213] However unlike our analysis, Evans & Peck manipulated the data in an attempt to normalise the projects and develop a sufficiently 'rich' data set and then manipulated the data again in order for it to fit a normal distribution curve.[214] We also note Evans & Peck did not rely on the statistical level of confidence to support its analysis. Thus we consider that each of the data manipulations overcomplicates the analysis and the findings are weakened without the support of statistical significance. EMCa supports our considerations:[215]

> The small sample size is an unavoidable factor, however we consider it to be a major weakness of the Evans & Peck analysis that statistical confidence levels are not reported and that the method used would not have facilitated a proper understanding of confidence levels. We consider it likely that, if properly determined, the Evans & Peck assessment of a 4.9% portfolio risk factor would have poor statistical significance.

We also consider the data manipulations are further compounded by the multiple cost calculations used to derive the 4.9 per cent cost estimation risk factor. We note the Evans & Peck analysis included differences between Level A (concept) estimates to Business Case and the Business Case to Outcome variances and then used multiplicative factors to adjust the results of these variances to derive the 4.9 per cent outcome. Again we consider this treatment an over complication of analysis. EMCa agreed and overall stated:[216]

> By analysing Level A to Business Case and Business Case to Outcome variances separately, by focusing on asymmetry rather than aggregate portfolio cost variance, by hypothesising the existence of contingencies, by its dataset including a large number of small projects that are not classified as augmentation, connection or replacement projects, by using a dataset selected by ElectraNet and containing a number of uncompleted projects and by making an 18.9% "normalisation" adjustment to all estimates, we consider that Evans & Peck has over–complicated the analysis and in the process has not produced a meaningful case or a meaningful value for adjusting the cost estimates produced by ElectraNet's cost estimation tool.

209 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 51, paragraph 214.
210 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 51, paragraph 214.
211 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 51, paragraph 215.
212 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 51, paragraph 215.
213 Evans & Peck*, ElectraNet capital program estimating risk analysis*, May 2012, p. 4.
214 Evans & Peck*, ElectraNet capital program estimating risk analysis*, May 2012, pp. 7–9.
215 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 52, paragraph 217.
216 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 52, paragraph 219.

Overall we consider the Evans & Peck analysis to be overly complicated and insufficiently transparent in which to draw robust conclusions.

ElectraNet also engaged Evans & Peck to comment on our final decision analysis.[217] Evans & Peck undertook further analysis based on the same data used by EMCa and MetService. Although Evans & Peck made some amendments to the data, the outcomes were similar to EMCa's and MetService's findings. EMCa agreed and noted:[218]

> We consider that the review and response provided by ElectraNet, and including Evans & Peck's notes, has been helpful in confirming our findings. It has confirmed that our understanding of the Evans & Peck analysis and of the data that ElectraNet provided to Evans & Peck was essentially correct, has identified two minor corrections to our base data and has confirmed that the results of analysis with these two corrections supports the conclusion that we reached and the recommendations that we have made.

Conclusion

We have considered both Evans & Peck findings and our assessment of actual historical outcomes. For the reasons discussed above, we have given weight to our findings on ElectraNet's actual historical outcomes rather than Evans & Peck's findings.

ElectraNet's proposal on cost estimation risk factor was based on an analysis of historical outcomes. Other stakeholders also considered the use of historical outcomes to be appropriate in determining future allowances.[219] Arguably, ElectraNet's recent investments and improvements in its asset management framework, data collection, project management and cost estimation processes would also improve its expenditure forecasting. We therefore, on balance, consider that it is reasonable to compare our draft decision cost estimation risk factor with ElectraNet's actual past outcomes.

On the basis of our analysis we consider ElectraNet's proposal overstates its capex requirement for the 2013–18 regulatory control period particularly in relation to its cost estimation risk factor. On balance, we consider that our draft decision forecast capex is prudent and efficient, and meets a realistic expectation of the demand forecast and cost inputs.[220] Therefore our final decision is to apply our draft decision on the cost estimation risk factor. This conclusion is also drawn by EMCa who recommends that we apply our draft decision cost estimation risk factors:[221]

> We recommend that the AER applies the same proportionate adjustments for portfolio risk and prudency as it applied in our draft decision.

We also consider that given our analysis compares actual expenditure with expenditure previously proposed for regulatory purposes it can be relied on to draw conclusions for both the cost estimation risk factor and prudency adjustment.[222] We consider this because it demonstrates both the exposure of ElectraNet's historical estimation risks and also the application of appropriate decisions at capital governance gateways resulting in prudency gains as projects progress. This consideration is supported by EMCa who noted:[223]

> ...it is reasonable to interpret it as encompassing both the concept of portfolio risk (that is, an asymmetric risk that the actual costs of the portfolio of projects may exceed the aggregate of ElectraNet's individual

217 ElectraNet, *Email response to information request AER RRP 17: CERF and prudency adjustment—Evans & Peck: Notes on MetService "Project Budget Estimation Analysis"*, March 2013.
218 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 121, paragraph 449.
219 Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, 18 February 2013, p. 4, Transgrid, *ElectraNet draft decision and revised revenue proposal 2013–2018*, February 2013, p. 3.
220 NER, clause 6A.6.7(c).
221 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 58, paragraph 248.
222 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 55, paragraph 235.
223 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 55, paragraph 235.

project cost estimates for the proposed projects) and also the extent to which engineering prudency applied at the project level reduce project costs as projects move from concept estimate through to realisation.

Our consideration of the prudency adjustment is set out below.

Prudency adjustment

We do not accept ElectraNet's revised proposal to not adopt the 7 per cent prudency adjustment set out in our draft decision. On the basis of our analysis above we consider ElectraNet's proposed replacement and refurbishment capex overstates its capex requirement for the 2013–18 regulatory control period. We consider in addition to the findings on the cost estimation risk factor, our analysis above informs our final decision on the appropriate prudency adjustment. That is our analysis demonstrates evidence of prudency gains as projects progress through ElectraNet's capital governance gateways. Based on our assessment, we maintain our draft decision 7 per cent prudency adjustment which we consider reasonably reflects the prudent costs of maintaining the quality, reliability and security of supply of ElectraNet's prescribed transmission services.[224]

The prudency adjustment is not an efficiency adjustment. Rather the principle of the prudency adjustment is that as projects transition from initial concept stage through ElectraNet's capital governance gateways to being fully scoped, alternative options become available. Some of these options will present lower cost alternatives than ElectraNet initially scoped. These options may include a change in scope of the project, deferral to a later regulatory control period or integrations with other projects which will benefit from economies of scale. In making these decisions at each gateway a TNSP can be expected to consider compliance with the required standards at least cost. This involves the marrying of engineering judgement with good capital governance to derive a capex forecast consistent with the capex criteria. Our prudency adjustments account for such decision making. If not, the forecast will be based largely on concept stage estimates without sufficient consideration of prudent decision making over the regulatory control period.

In our draft decision, the prudency opportunities and the appropriate adjustment was derived through our sample of projects review.[225] However, we acknowledge ElectraNet's considerations that it may not be reliable to extrapolate our findings from this small sample across the entire replacement and refurbishment program.[226] Nevertheless, we note ElectraNet's revised proposal relating to EMCa's findings on our draft decision provides support for prudency opportunities.[227] However, we recognise that the appropriate adjustment based on a small sample should be reconsidered.

We note ElectraNet's consideration that its historical outcomes can be used to inform forecast costs.[228] Thus we consider that our analysis above is relevant to determining the appropriate adjustment for prudency gains in forecasting capex for this final decision. As noted above the actual historical outcomes show a large forecast overestimation. On this basis, we consider our analysis above supports both the principle of applying the prudency adjustment and the 7 per cent adjustment applied in our draft decision.

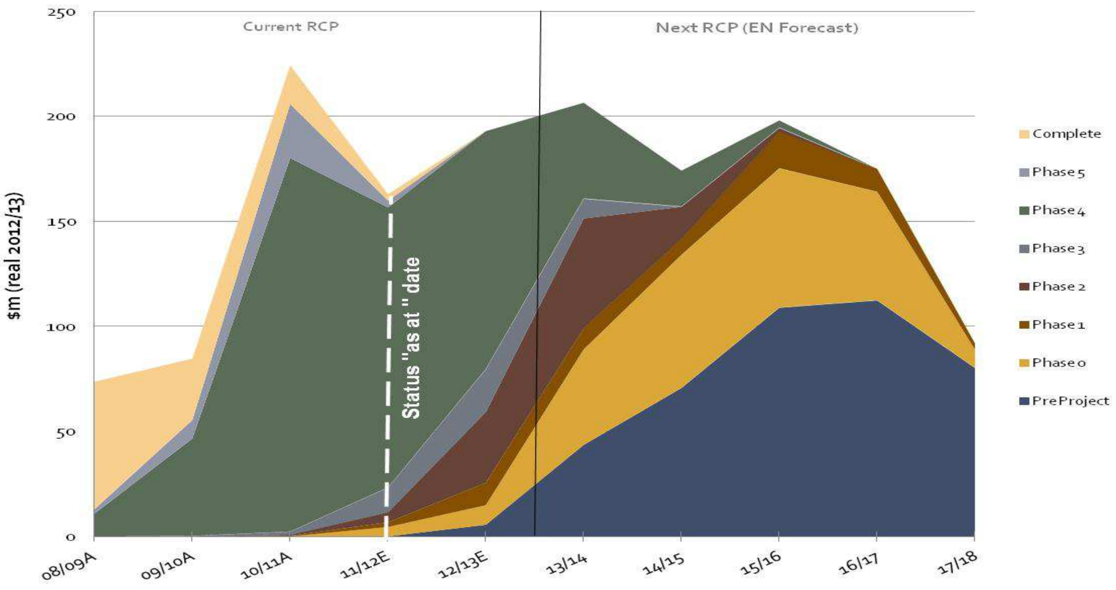
Our draft decision applied a 7 per cent prudency adjustment to ElectraNet's proposed replacement and refurbishment capex.[229] As presented in figure 2.2 below, ElectraNet's forecast capex contains a significant proportion of projects that are still in the early stages of development. As a result, detailed

224 NER, clause 6A.6.7(a)(3), (c)(1) and (2).
225 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 123–5.
226 ElectraNet, *Revised revenue proposal*, p. 54.
227 ElectraNet, *Revised revenue proposal*, pp. 54–6; EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 107, paragraph 409.
228 ElectraNet, *Revised revenue proposal*, pp. 53–4.
229 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 123–5.

cost scoping for these projects is yet to be developed. We considered that prudency gains will be captured as projects move through the capital governance gateways of ElectraNet's asset management framework. For example, as projects pass through the gateways decision can be made to undertake alternative options which can include change of scope, deferrals and integrations with other projects. Our draft decision was underpinned by EMCa's sample project review.[230]

EMCa's sample project review included eight of ElectraNet's proposed replacement projects (47 per cent of the total replacement capex in value). EMCa was able to quantify potential prudency gains of 7 per cent of the total capex of the replacement projects reviewed.[231] EMCa concluded that this level of efficiency and prudency gain should be achievable across all of ElectraNet's proposed replacement and refurbishment capex.[232] EMCa considered this is consistent with its findings on ElectraNet's management of its capex over the 2008–13 regulatory control period.[233]

Figure 2.2 ElectraNet capex by PMM phase ($ million, 2012–13)



Source: EMCa, *ElectraNet technical review*, October 2012, p. 58, figure 17.

ElectraNet's revised proposal did not adopt the prudency adjustment set out in our draft decision.[234] ElectraNet considered that the potential savings in each project sampled by EMCa was incorrect and not statistically robust. ElectraNet therefore submitted that it was inappropriate to extrapolate these across the entire replacement and refurbishment program.[235] Further, ElectraNet considered its forecasts were based on the 'most likely' estimates and is unaware of any evidence demonstrating unidentified efficiencies which are quantifiable now.[236] ElectraNet refers to the Evans & Peck analysis which presents that the current regulatory period indicates that "most likely" cost estimates are

230 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraphs 340–344 and 702–704.
231 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraphs 340–344 and 702–704.
232 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraphs 340–344.
233 EMCa, *ElectraNet technical review*, October 2012, p. 97, paragraph 345.
234 ElectraNet, *Revised revenue proposal*, pp. 52–9.
235 ElectraNet, *Revised revenue proposal*, pp. 52–9.
236 ElectraNet, *Revised revenue proposal*, p. 53.

underestimated by an average of 15 per cent.[237] ElectraNet's considerations are supported by submissions by other TNSPs—Transend and TransGrid.[238]

Our final decision analysis above demonstrates that in the 2008–13 regulatory control period there was a significant asymmetry between ElectraNet's estimated costs and its actual costs for its replacement capex projects. Table 2.8 is a summary of table 2.6 and table 2.7 which present the EMCa and MetService analysis highlighting the asymmetry between ElectraNet's replacement estimated and actual costs in the 2008–13 regulatory control period.

Table 2.8 Summary of EMCa and MetService analysis of estimated versus actual replacement project costs in the 2008–13 regulatory control period (per cent)

Analysis	Replacement projects (per cent)
EMCa analysis	–14%
MetService analysis —Non-parametric bootstrap	–16%
MetService analysis —Bayesian	–16%

Source: EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 56, paragraph 239. MetService, *Project budget estimation analysis*, 17 February 2013.

We consider this significant asymmetry is not entirely related to cost estimation risk but also a demonstration of ElectraNet's decisions at capital governance gateways resulting in prudency gains. Specifically, we consider this demonstrates that as ElectraNet's early stage replacement and refurbishment projects move through its capital governance gateways to detailed costing prudency gains are captured. Considering the significant proportion of early stage replacement and refurbishment projects in ElectraNet's capex proposal we consider it reasonable to conclude this trend will continue through the 2013–18 regulatory control period. This is consistent with the NER which requires that the capex forecast reflect the efficient costs that a prudent operator in ElectraNet's circumstances would need to incur.[239]

We consider ElectraNet's proposal overstates its capex requirement for the 2013–18 regulatory control period particularly in relation to its replacement and refurbishment capex. We consider ElectraNet has not sufficiently accounted for its own actions on continuous improvements. Our analysis has established that there is likely to be little risk that ElectraNet's proposed replacement and refurbishment capex will actually be higher than estimated. Rather, the analysis demonstrates that ElectraNet's forecast replacement and refurbishment capex is likely to be overestimated.

Therefore our final decision is to apply our draft decision on the cost estimation risk factor and prudency adjustment. This conclusion is supported by EMCa who stated:[240]

> Given the mean out-turn for "replacement" projects of a 16 per cent under-run, the application of the previously assumed "prudency adjustment" of –7 per cent, and zero portfolio risk factor, is a more likely outcome than application of a risk factor of +4.9 per cent (and no prudency allowance). As per the Draft Decision, this would imply a reduction of 4.9 per cent plus 7 per cent for a total of 11.9 per cent to the portfolio budget of replacement and refurbishment projects proposed by ElectraNet.

237 ElectraNet, *Revised revenue proposal*, pp. 53–4.

238 Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, 18 February 2013, pp. 2–3, TransGrid, *ElectraNet draft decision and revised revenue proposal 2013–2018*, February 2013, pp. 1–2.

239 NER, clause 6A.6.7(c).

240 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 57, paragraph 243.

Capex–opex trade off

We have made an adjustment of $5.5 million ($2012–13) to ElectraNet's proposed replacement capex for our final decision capex–opex trade off adjustment. See operating expenditure attachment 3 for discussion on this adjustment.

Real cost escalators

We do not accept ElectraNet's revised revenue proposal real cost escalators reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.[241] We consider ElectraNet's proposed real cost escalators are in excess of expenditure required to achieve the capex objectives.[242] We have determined the substitute escalators which we consider reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives. These are:

- labour cost forecasts developed by Deloitte Access Economics (DAE)
- exchange rates and forecast inputs for material and land value escalation updated to reflect most recent data.

Attachment 1 contains our consideration of the ElectraNet's revised real cost escalators. The impact of the application of our real cost escalators on ElectraNet's revised proposed capex is shown in table 2.9.

Table 2.9 Impact of AER's final decision real cost escalation on capex ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2018–19	Total
ElectraNet revised proposal	0.7	2.4	5.9	7.3	4.3	20.6
AER final decision	1.0	2.5	4.5	4.3	2.3	14.6
Difference	–0.2	–0.1	1.4	2.9	2.0	6.0

Source: AER analysis. Numbers may not add due to rounding.

2.4.3 Strategic land and easements acquisitions

We do not accept ElectraNet's revised revenue proposal strategic land and easements capex of $41.5 million ($2012–13). Our final decision is to substitute ElectraNet's proposed strategic land and easements capex with $30.7 million ($2012–13). This substitute forecast is $10.7 million ($2012–13) less than ElectraNet's revised revenue proposal but $17.2 million ($2012–13) more than our draft decision.

Table 2.10 shows the impact of our substitute forecast. For three acquisitions all of the capex was included in our substitute forecast while we accept part costs for two acquisitions. None of the Fleurieu Peninsula reinforcement land acquisition costs are included in our substitute forecast.

241 NER, clause 6A.6.7(c)(3).
242 NER, clauses 6A.6.7(a)(3) and (4).

Table 2.10 The AER's final decision on ElectraNet's proposed strategic land and easement capex ($ million, 2012–13)

	Total
ElectraNet revised proposal	41.5
Defer	10.7
AER final decision	30.7

Source: AER analysis; ElectraNet, *Revised revenue proposal, Appendix I 'Strategic land acquisition business cases'*, 16 January 2013. Numbers do not add due to rounding.

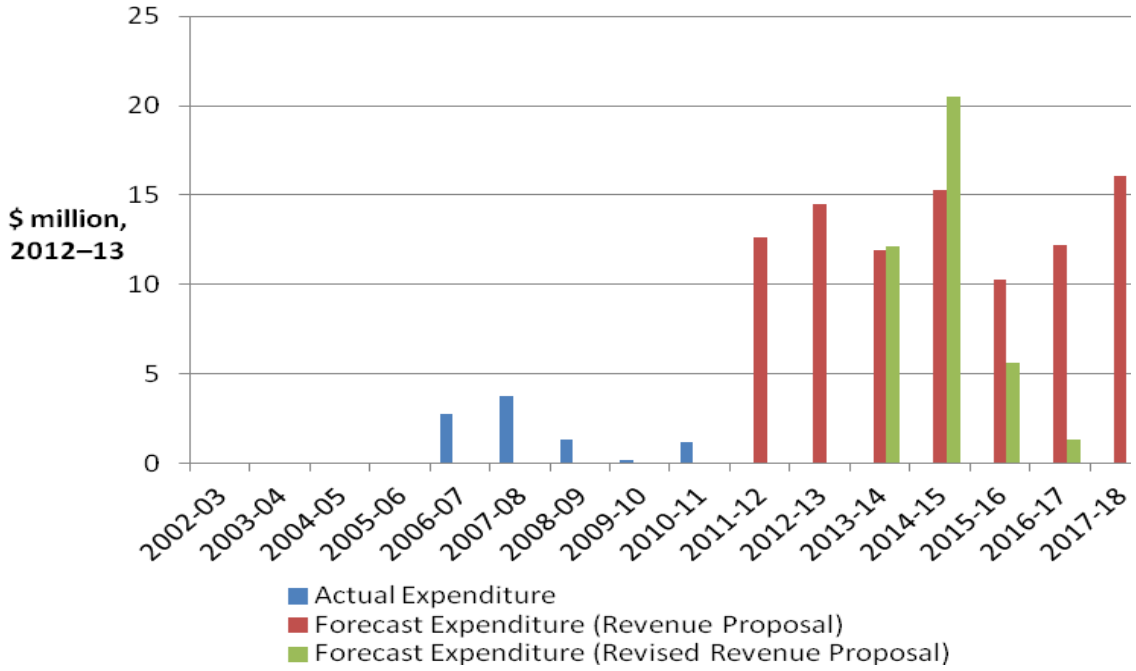
Land parcels and easements are considered strategic if they are purchased in advance of their need for a transmission project. In some cases the period between acquisition and their eventual use could be up to 30 years.[243] EMCa noted that this could give rise to 'land banking'.[244] That is, the accumulation of land parcels and easements once acquired remain undeveloped for a significant period of time. Despite this we consider strategic land and easement acquisitions can be appropriate. Yet for such expenditure to be approved under the capex objectives and criteria in the NER, it must be prudent and efficient.[245] Moreover, it must be consistent with the NEL objective, which is:

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
>
> a. price, quality, safety, reliability, and security of supply of electricity; and
>
> b. the reliability, safety and security of the national electricity system.

Figure 2.3 shows ElectraNet's actual and forecast strategic land and easement capex.[246] Historically, ElectraNet's actual costs relating to strategic land and easement acquisitions averaged $0.8 million per year for the 2008–09, 2009–10 and 2010–11 regulatory years.[247]

243 ElectraNet, *Revised revenue proposal, Appendix I 'Strategic land acquisition business cases'*, 16 January 2013, p. 5.
244 EMCa, *ElectraNet technical review - revised revenue proposal,* April 2013, p. 66, paragraph 270
245 NER, clause 6A.6.7(a)(c)(1)–(2).
246 ElectraNet, *Revenue proposal*, 31 May 2012, p. 76.
247 ElectraNet, *Revenue proposal*, 31 May 2012, p. 76.

Figure 2.3 ElectraNet's actual and forecast strategic land and easement capex ($2012–13)



Source: ElectraNet, *Revised revenue proposal*, 16 January 2013.

Assessment approach

ElectraNet's revised revenue proposal included business cases for each strategic land and easement acquisition. These contained economic evaluations assessing the cost of acquiring a land parcel and easement in the 2013–18 regulatory control period as compared against the next best alternative. Qualitative reasons for making each strategic acquisition were also provided. For example, information regarding any urban and regional developments which could prevent the acquisition of the best site for a transmission project.

In assessing ElectraNet's business cases we considered a range of factors. These were the same as those which EMCa considered in its technical review, and include:[248]

- whether the land parcel or easement will definitely be required in the next 20 years
- whether known reasonable alternative routes exist for the line due to system design, geographic, environmental or competing development constraints
- whether a high risk of encroachment on the line route from urban or semi urban development could delay or prevent the acquisition of a land parcel or easement
- the discount rate used to escalate the net present costs of purchasing land early as opposed to later, and the results of that analysis
- whether the only available solution would be to underground a transmission line should an encroachment risk materialise, with consequently much higher capital cost

248 EMCa, *ElectraNet technical review - revised revenue proposal,* April 2013, p. 65, paragraph 269

- if the project has been evaluated to consider the cost benefits of being split to purchase easements for high risk areas only with lower risk areas deferred.

Our reasoning in this final decision differs from our draft. In our draft decision, 11 land and easement acquisitions were excluded from our indicative substitute forecast since they were already designated for ElectraNet's use by planning instruments.[249] For example, the 30 Year Greater Adelaide Plan and council designations. We considered this to be a prudent and efficient approach because planning instruments would alleviate the risk of encroachment while deferring capex until a land parcel or easement is actually needed.

ElectraNet provided a letter from the South Australian Department of Planning, Transport and Infrastructure clarifying that planning instruments cannot guarantee development rights.[250] Their legislative effect is to merely provide assurances regarding land use policy rather than prohibit a competing land user from encroaching on a particular land parcel or easement. The South Australian Minister for Mineral Resources and Energy also stated that 'it is important to note that State planning legislation does not guarantee development rights'.[251] Hence no weight was given to the planning instruments in this final decision.

In general a strategic land and easement acquisition will only be prudent and efficient if there is a risk of encroachment. That is, the risk of a competing land user encroaching on a land parcel or easement which ElectraNet is certain to need in the future but has yet to acquire. If such a risk exists, then the proposed expenditure is likely to satisfy the capex objectives and criteria.[252] This is because acquiring a land parcel or easement before it is needed (that is, strategically) can avoid more costly outcomes associated with encroachment; for example, the rerouting or undergrounding of a transmission line. Such outcomes may not be in the long term interest of electricity consumers.

We assessed all six proposed land parcels and easements. For each we concluded whether all, part or none of the forecast capex should be included in our substitute forecast.

All of the forecast costs approved

We approved the entire ElectraNet's forecast capex for three land parcels and easements in our total substitute forecast. These are the Eyre Peninsula land acquisition, the Mount Barker south easement expansion and the Cultana to Stony Point land and easement acquisition.

The Mount Barker acquisition involves the widening of an existing easement which runs for 5.1 km. This proposed easement expansion is needed for the replacement of an existing triple circuit 275 kV line in the next 20 to 30 years. The project area parallels an existing housing development posing a material risk of encroachment from further residential developments. It would therefore be prudent and efficient for the land and easement acquisition to be made in the 2013–18 regulatory control period. We include all of the proposed capex in our substitute total forecast for this reason.

The Cultana to Stony Point land and easement acquisition, once purchased, will provide for an additional 50m in width for a new 275kV line over 25km. It also covers the cost of land for a substation at Stony Point. EMCa's technical review accepted there is a real prospect of having to underground sections of the planned 275kV line if the land and easement acquisition was delayed beyond the

249 AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 130.

250 John Hanlon, Deputy CEO Planning Division, South Australian Department of Planning, Transport and Infrastructure, Letter addressed to ElectraNet, 13 December 2012.

251 Hon Tom Koutantonis MP, Minister for Mineral Resources and Energy, 'Letter addressed to the AER', 2 March 2013

252 NER, clause 6A.6.7(a)(c)(1)–(2).

2013–18 regulatory control period.[253] This uneconomic outcome is avoidable if a strategic land and easement acquisition is made. Hence, we approved all of the proposed expenditure for the Cultana to Stony Point acquisition.

We approve the entire forecast capex for the Eyre Peninsula Reinforcement land acquisition. We received submissions supporting its acquisition.[254] The submissions affirmed the importance of the Eyre Peninsula land acquisition and the need for it to be purchased early to prevent delays in the delivery of the anticipated transmission corridor and substation. ElectraNet also provided a strong business case supporting the proposed acquisition. Through our assessment we consider the proposed Eyre Peninsula Reinforcement land acquisition are critical and must be acquired in the 2013–18 regulatory control period. We also consider the proposal is prudent and efficient, so the full forecast capex of its purchase is included in our total substitute forecast.

Part of the forecast costs approved

We include part of the forecast capex of two land parcels and easement in our total substitute forecast. They are the Para to Malla and Templers to Para land and easement acquisitions. For both of these, ElectraNet proposed staging its land and easement purchases over multiple regulatory control periods. That is, ElectraNet would acquire sections of a transmission corridor in the 2013–18 regulatory control period and the remainder in a later period.

We consider the staging of strategic land and easement costs to be prudent and efficient, and have accepted this option in both instances in which ElectraNet raised it as a suitable alternative. The result is a reduction in the proposed capex for the Malla to Parra and Templers to Parra land and easement acquisitions.[255] We consider this to be prudent and efficient because it allows ElectraNet to acquire the most critical sections of a land parcel or easement. This overcomes the immediate risk of encroachment and is more cost effective in the 2013–18 regulatory control period.

None of the forecast costs approved

Our total substitute forecast does not include capex for the Fleurieu Peninsula reinforcement land acquisition. This project is 65 km long by 50 m wide, and is intended for a 275kV line from Kanmantoo to Currency Creek. Completion of the construction for this transmission project is not expected until 2024 although ElectraNet submitted that early completion of the land acquisition is required because of difficulties in securing planning approvals. It also noted the long lead time associated with consulting with parties affected by the construction of the 275kV transmission line in a visually sensitive area. Centrex provided a submission attesting to the long lead times often associated with negotiating a corridor for infrastructure.[256]

However, in its business case for the Fleurieu Peninsula reinforcement ElectraNet did not provide adequate justification supporting a strategic acquisition. The discounted cost of making the acquisition in the 2013–18 regulatory control period was determined to be $14.6 million ($2012–13). The alternative, involving delaying the acquisition until 2022 and rerouting 5km of easement, was estimated to be only marginally more, at $15.8 million ($2012–13). In addition, EMCa observed that

[253] EMCa, *ElectraNet technical review - revised revenue proposal,* April 2013, p. 96, paragraph 401

[254] Iron Road, *Submission on the AER's draft decision and ElectraNet's revised revenue proposal*, 18 February 2013, p.7; South Australian Department of Manufacturing, Innovation, Trade, Resources and Energy, *Submission on the AER's draft decision and ElectraNet's revised revenue proposal*, 18 February 2013.

[255] ElectraNet, *Revised revenue proposal, Appendix I 'Strategic land acquisition business cases: Para to Mallala*' 16 January 2013, p. 10; ElectraNet, *Revised revenue proposal, Appendix I 'Strategic land acquisition business cases: Templers to Para'*, 16 January 2013, p. 10

[256] Centrex, *Submission on the AER's draft decision and ElectraNet's revised revenue proposal*, 19 February 2013, p. 3.

ElectraNet's net present value analysis was 'skewed' by estimating the additional cost of rerouting 5 km of easement at $12 million ($2012–13).[257] EMCa reasoned that this was excessive.[258]

Therefore, we conclude that the low cost advantage of acquiring the land in the 2013–18 regulatory control period means that it would not be a prudent or efficient purchase. There are also low encroachment risks, since it is in a remote area with few urban and regional developments that would make an acquisition uneconomic:[259]

> The region is currently largely agricultural, with a mixture of tourist, low level industrial and mining. It is anticipated that there may be intensive mining growth in the future. The line passes through predominately farming land of various types, none of which are likely to make it uneconomic to obtain easements at a later date. Furthermore, the terrain is of an open nature which would allow easy re-routing a relatively low cost.

Conclusion

Our final decision is to substitute ElectraNet's proposed capex for strategic land and easements with $30.7 million ($2012–13). This substitute forecast was determined by accepting all, part or none of the forecast capex for each proposed land and easement acquisition. We consider our substitute forecast is line with the capex criteria and objectives, and it reasonably reflects the efficient capex of a prudent TNSP.[260]

2.4.4 Equity raising costs

Our draft decision accepted ElectraNet's proposed method for determining its benchmark equity raising costs allowance associated with its forecast capex. We consider 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.

We have updated ElectraNet's proposed equity raising cost allowance to reflect our final decision RAB roll forward and WACC. Our final decision, therefore, is to provide an allowance for equity raising costs of $0.4 million ($2012–13). The derivation of ElectraNet's equity raising costs allowance is shown in table 2.11 and table 2.12.

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257 EMCa, *ElectraNet technical review - revised revenue proposal,* April 2013, p. 95, paragraph 387.
258 EMCa, *ElectraNet technical review - revised revenue proposal,* April 2013, p. 95, paragraph 387.
259 EMCa, *ElectraNet technical review - revised revenue proposal,* April 2013, p. 95, paragraph 386.
260 NER, clause 6A.6.7(a)(c)(1)–(2).

Table 2.11 AER's final decision cash flow analysis for ElectraNet's benchmark equity raising costs ($ million, nominal)

Cash flow analysis	Total	Notes
Dividends	195.6	Set to distribute imputation credits assumed in the PTRM (100 per cent).
Dividends reinvested	58.7	Availability of reinvested dividends, capped at 30% dividends paid.
Capex funding requirement	736.6	Forecast capex funding requirement (including half year WACC adjustment).
Debt component	330.2	Set to equal 60% of annual change in RAB.
Equity component	406.4	Residual of capex funding requirement and debt component.
Retained cash flow available for reinvestment	367.6	Exclude dividends reinvested.
Equity required	38.8	Equals equity component less retained cash flows.

Source: AER analysis.

Table 2.12 AER's final decision cash flow analysis for ElectraNet's benchmark equity raising costs ($ million, 2012–13)

Cash flow analysis	Total	Notes
Equity component	378.9	Residual of capex funding requirement and debt component.
Retained cash flow available for reinvestment	340.6	Exclude dividends reinvested.
Equity required	38.3	Equals equity component less retained cash flows.
Dividends reinvested	54.4	Availability of reinvested dividends, capped at 30% dividends paid.
Dividend reinvestment plan required	38.3	Required reinvested dividends.
Seasoned equity offerings required	0.0	Required season equity offerings (SEOs).
Cost of dividend investment plan	0.4	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	0.4	Total costs of dividend reinvestment plan and SEOs. To be added to RAB at the start of the regulatory control period.

Source: AER analysis.

2.4.5 Components of ElectraNet's revised capex proposal that the AER accepts

We accept the categories of ElectraNet's revised forecast capex in table 2.13 reasonably reflect the efficient and prudent costs of a TNSP. Table 2.13 sets out the categories and accepted values.

Table 2.13 Components of ElectraNet's capex proposal that the AER accepts ($ million, 2012–13)

Project category	Sub-category	$ million, 2012–13
NETWORK		
Load driven	Augmentation	87.1
	Connection	86.9
Non-load driven	Security/compliance	64.9
	Inventory/spares	18.6
NON-NETWORK		
	Business IT	45.8
	Buildings/facilities	5.6

Source: AER analysis. Numbers may not be the same as ElectraNet's proposal due to our final decision on cost estimation risk factors and real cost escalation.

We accept that ElectraNet's revised proposed forecast augmentation and connection capex reasonably reflect a realistic expectation of the demand forecast and cost inputs required to meet the capex objectives.[261] ElectraNet's revised proposed augmentation and connection capex is a $74.4 million ($2012–13) reduction of its initial revenue proposal. This reduction reflects ElectraNet's revised revenue proposal's lower demand forecast.

Our draft decision applied adjustments to ElectraNet's proposed augmentation and connection capex as we considered its demand forecast was overstated.[262] Consistent with EUAA's considerations, we have reviewed ElectraNet's revised proposed augmentation and connection capex accounting for its revised demand forecast.[263] We consider that ElectraNet's revised augmentation and connection capex is consistent with a realistic expectation of the demand forecast and the adjustments applied in our draft decision. On this basis, we accept ElectraNet's revised augmentation and connection capex. This conclusion is supported by EMCa who stated:[264]

> We consider that the augmentation and connection capex proposed in ElectraNet's RRP is reasonable and we recommend that it should be accepted.

We accepted the following capex categories in our draft decision:

- security/compliance
- inventory spares
- business IT
- buildings and facilities.

For our final decision we have again reviewed these capex categories in ElectraNet's revised proposal. We note the revised revenue proposal contains updated expenditures for these categories which reflect most recent data for work in progress projects. Based on our review we consider

261 NER, clause 6A.6.7(c)(3) and 6A.6.7(1).
262 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 133–5.
263 EUAA, *Submission to the AER on ElectraNet revenue draft determination 2013/14 to 2017/18*, February 2013, p. 22.
264 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p.13, paragraph 53.

ElectraNet's revised proposed capex for these categories to reasonably reflect a realistic expectation of the cost inputs required to meet the capex objectives.[265]

The effect of the South Australian Electricity Transmission Code

In its revised revenue proposal ElectraNet revised down its demand forecast which resulted in a smaller connection and augmentation capex forecast which we accept as part of its total forecast capex. However, subsequent to our draft decision, ElectraNet:

- applied to the Essential Services Commission of South Australian (ESCOSA) to amend the definition of forecast agreed maximum demand (FAMD) in the South Australian Electricity Transmission Code (ETC).
- proposed a cost pass through event which it described as being triggered in the event the ESCOSA decision results in a more onerous forecast demand obligation under the ETC than the demand forecasts accepted by the AER as part of its final decision. The proposed cost pass though is discussed in appendix 13.[266]

In its revised proposal ElectraNet stated that it has now adopted a ten per cent probability of exceedance (POE) connection point demand forecast for the purpose of non-radial and regional connection point planning. It further stated: [267]

> the change in basis for the demand forecasts involves accepting a marginal increase in risk to supply reliability – that is, some customer load may need to be shed under peak load conditions (exceeding 10 per cent probability of exceedance demand forecast conditions) during an outage of a critical transmission element.

It appears that ElectraNet is concerned that if our decision in this transmission determination is to allow a forecast total capex that does not reflect FAMD then it will not have sufficient capex to meet its obligations under the ETC. For the reasons set out below we consider our capex allowance is not inconsistent with ElectraNet's obligations under the ETC.

If there is anything inconsistent between the NER and the ETC, the provisions of the NER have priority to the extent of the inconsistency, except where ElectraNet's obligations under the ETC are 'higher or more onerous'.[268] We consider that there is no obligation in the ETC that is higher or more onerous than ElectraNet's obligation to forecast total capex to meet a realistic expectation of demand.[269]

In our draft decision we accepted ElectraNet's obligations under the ETC are applicable regulatory obligations under the NER and NEL.[270] We accept this extends to clause 2.11.[271] However, as stated in our draft decision, we do not accept ElectraNet's characterisation of its obligations under the ETC as obligations which require ElectraNet to accept SA Power Networks' demand forecast 'as is'.[272] Clause 2.11 of the ETC requires ElectraNet to react to a change in FAMD to ensure it has sufficient capacity to meet the reliability standards.[273]

265 NER, clauses 6A.6.7(c)(3) and 6A.6.7(1).
266 ElectraNet, *Revised revenue proposal*, 16 January 2013, p. 36.
267 ElectraNet, *Revised revenue proposal*, 16 January 2013, p. 29.
268 ETC, TC/07, effective 1 July 2013, clause 1.6.2, p. 2.
269 NER, clause 6A.6.6(c)(3).
270 AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 92.
271 Clause 2.11 of the ETC requires ElectraNet to react to a change in FAMD to ensure it has sufficient capacity to meet the reliability standards.
272 AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 87.
273 ETC, TC/07, effective 1 July 2013, clause 2.11, p.8.

As set out in our draft decision, we consider there are three relevant obligations under the ETC. ElectraNet must:

- reliably supply contracted AMD. [274]
- react to a change in FAMD to ensure it can reliably supply contracted AMD.[275]
- plan, develop and operate its network such that there will be '*minimal requirements to shed load under normal and reasonably foreseeable operating conditions*'.[276]

Obligation to reliably supply contracted agreed maximum demand

ElectraNet's obligations under the ETC are to ensure that it can reliably supply contracted[277] agreed maximum demand (AMD).[278] ElectraNet agreed that the relevant reliability standard is set by reference to contracted AMD.[279] The specific standards ElectraNet must meet in supplying contracted AMD are set out in clauses 2.1 to 2.9 of the ETC. In general, these standards require ElectraNet to provide a specified level of line capacity and transformer capacity to meet 100 per cent of contracted AMD.

Obligation to react to a change in FAMD

ElectraNet's obligation to react to a change in FAMD is set out in clause 2.11 of the ETC. Clause 2.11 requires ElectraNet to react to ensure that its network capacity is sufficient to meet the required standard within a specified time frame. It must react in the event that a change in FAMD *'will result in a future breach of a standard*'.[280] However, we note that a change in FAMD of itself cannot result in a future breach of the standard because the standards are set by reference to contracted AMD, not FAMD.

ElectraNet stated that the obligation to react to a change in FAMD is an applicable regulatory obligation '*for the purposes of determining forecast capex*.'[281] The obligation to react to a change in FAMD was introduced by ESCOSA to provide ElectraNet and SA Power Networks a three year 'extended forward planning window' in which to respond to anticipated breaches of the ETC.[282]

Previously, ElectraNet was required to respond to breaches of the reliability standards within 12 months of the date of a breach. Now, FAMD provides a trigger for ElectraNet to consider whether it will need to act now to ensure it can meet its anticipated reliability obligations in three years time. This involves an assessment of what its contracted AMD is likely to be. However, there is nothing in the ETC that requires ElectraNet to contract AMD at the level of FAMD. At this point in time, there is no evidence before us to suggest that the demand forecasts underlying ElectraNet's capex proposal are likely to be inconsistent with FAMD over the course of the regulatory period.

Nature of FAMD

274 ETC, TC/07, effective 1 July 2013, clause 2, pp. 2–11.
275 ETC, TC/07, effective 1 July 2013, clause 2.11, p. 8
276 ETC, TC/07, effective 1 July 2013, clause 2.1, p. 2. Subject to its obligation in clause 2 to reliably supply contracted AMD.
277 Under the *Transmission Connection Agreement*, between SA Power Networks and ElectraNet, dated November 1999.
278 Agreed maximum demand is a term defined in clause 1.1 of *the Transmission Connection Agreement* between SA Power Networks and ElectraNet, dated November 1999, p. 2.
279 ElectraNet, *Revised revenue proposal*, p. 34.
280 ETC, TC/07, clause 2.11, p.8 effective 1 July 2013.
281 ElectraNet, *Revised revenue proposal*, p. 34.
282 ESCOSA, *Review of the Electricity Transmission Code*, final decision, February 2012, p. 30.

The definition of FAMD means that FAMD must be agreed between ElectraNet and SA Power Networks. Therefore, ElectraNet is not required to accept SA Power Networks demand forecast 'as is' for the purpose of agreeing FAMD.

FAMD means:

> the agreed maximum demand forecast for a given year that is agreed with the customer three years prior to when the agreed maximum demand is contracted.

As discussed in our draft decision, FAMD is a definition only, it is not an obligation to forecast demand.[283] However, we recognise, inherent in ElectraNet's obligation to agree FAMD and to react to a change in FAMD is the need to develop a forecast of demand that is capable of meeting the definition of FAMD.[284] While we recognise this inherent need to forecast demand, there is no *obligation* in the ETC to forecast demand.

We note the submission from the South Australian Minister for Mineral Resources and Energy, Mr Tom Koutsantonis MP that we:[285]

> should ensure that the forecasting methods used in revenue determinations are consistent with those for determining reliability levels.

While there is no obligation in the ETC that requires ElectraNet to forecast demand, we consider that forecasting for the purposes of the ETC and for the purposes of a revenue proposal complement each other. We agree that each purpose may benefit from a consistent forecasting approach.

Cost of reacting to a change in FAMD

By providing a minimum three year planning window in which to determine FAMD, the ETC provides a framework for ElectraNet to consider the need to augment its network to ensure it has sufficient capacity to reliably supply the level of AMD it expects to contract in the future.

We note ElectraNet's comments in its revised regulatory proposal regarding its obligations under the ETC and the application of section 7A(2) of the NEL.[286] ElectraNet submitted that an obligation:[287]

> ....to react to a change in forecast agreed maximum demand contributes to the cost of ElectraNet in providing direct control services and therefore the AER is required to take into account those costs when determining ElectraNet's forecast capex for the purposes of its transmission determination.

The obligation to react to a change in FAMD does not necessarily require ElectraNet to incur costs in excess of the forecast total capex provided in a revenue determination. There is nothing at this point in time to suggest ElectraNet should anticipate contracting above a realistic expectation of demand.

Proposed change to the definition of FAMD

ElectraNet's application to ESCOSA proposed changes to the definition of FAMD in the ETC. The changes contemplated a definition of FAMD that is based on a 10 per cent POE forecasting methodology. In our view there is nothing in the current ETC that prohibits either ElectraNet or SA Power Networks from developing a forecast of demand for the purpose of agreeing FAMD based on 10 per cent POE.

283 AER, *Draft decision: ElectraNet transmission determination*, November 2012, p. 92.
284 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 92 to 93.
285 Mr Tom Koutsantonis MP, South Australian Minister for Mineral Resources and Energy, *Letter to the AER*, 2 March 2013.
286 ETC, TC/07, 1 July 2013.
287 ElectraNet, *Revised revenue proposal*, p. 35, January 2013.

A change to the definition of FAMD as proposed by ElectraNet in its application to ESCOSA will not convert FAMD to an obligation to forecast demand. It will, however, necessarily prescribe the basis upon which a demand forecast may be developed to derive FAMD.

Obligation to plan, develop and operate its network

The ETC requires ElectraNet to use its best endeavours to plan, develop and operate its transmission system and network to meet the NER standards in relation to the quality of its services and reliability of its network.[288]

Subject to ElectraNet's obligation to reliably supply contracted AMD, it must plan, develop and operate its:

- *network* such that there will be no requirement to shed load to achieve the NER standards; and
- *systems* such that there will be minimal requirements to shed load.

However, the ETC only requires ElectraNet to plan its network and systems to minimise or shed load '*under normal and reasonably foreseeable operating conditions*'.

The ETC requires ElectraNet to have sufficient capex to plan its network and systems sufficient to allow it to minimise or not shed load under '*normal and reasonably foreseeable operating conditions*'.

We consider that ElectraNet will have planned its network to not shed load under reasonably foreseeable operating conditions when it forecasts demand based on a realistic expectation of demand. To that extent, the planning requirement in the ETC is not inconsistent with ElectraNet's obligation to forecast total capex based on a realistic expectation of demand for the purposes of this determination.

There is always the potential for peak demand to exceed capacity. If ElectraNet needs to shed load in times of peak demand, it does not necessarily breach the ETC. The ETC requires ElectraNet to plan its network to meet demand under reasonably foreseeable operating conditions only. Neither the ETC, nor the NER, require ElectraNet to plan its network so that it is never required to shed load in times of peak demand. To do so has the potential to impose extremely high costs on customers.

2.4.6 Grandfathering provisions in clause 11.6.11

We maintain our draft decision of accepting ElectraNet's proposed replacement capex relating to SA Water pumping stations in its total capex forecast for the 2013–18 regulatory control period. In our draft decision, we accepted ElectraNet's proposed replacement capex relating to SA Water pumping stations due to grandfathering arrangements contained in clause 11.6.11 of the NER.[289] We noted that due to the grandfathering arrangements we had limited scope to make adjustments to ElectraNet's proposal. However, we recommended a review of clause 11.6.11.

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

288 ETC, TC/07, effective 1 July 2013, clauses 2.1 and 2.2, p. 2.
289 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 126–8.

connection asset would provide a negotiated service and expenditure associated with providing negotiated services could not be included in ElectraNet's revenue proposal.

Transend and the EUAA provided submissions which support the review of clause 11.6.11. The Transend submission acknowledged that grandfathering arrangements may extend longer than the 'Rule maker' anticipated with possible unintended consequences for efficient investment decisions.[290] The EUAA submission reflected the concerns we raised in our draft decision and proposed that the replacement capex for the SA Water pumping stations be classified as contingent projects capex for a more detailed review.[291]

While we acknowledge EUAA's proposal to consider these replacement projects as contingent projects, we consider we are unable to do so under the NER. In order to classify these projects as contingent projects, we would need to establish that the event or the costs associated with the event must be uncertain.[292] However, we consider that both the event and costs related to this expenditure are reasonably certain. In relation to the certainty of the event:

- our draft decision acknowledged that, due to their age and condition, these pumping station assets require replacement over the 2013–18 regulatory control period[293]
- given that SA Water confirmed that it requires the current level of service, the project scope is also certain.[294]

Therefore we consider that the replacement of these assets is certain.

In relation to the certainty of the costs, for our draft decision we attempted to engage in a consultative discussion with EMCa, ElectraNet, and SA Water to ascertain whether it was possible to investigate a better approach. However, SA Water responded that it was satisfied with the existing service level and would not be seeking changes to it.[295] We note SA Water would incur an increase in its charges should it request a change in service level as these services would become negotiated services. Therefore the incentive to request a change in service levels is significantly diminished. Given that SA Water confirms that it will not be requesting a change in service levels, ElectraNet has no scope to make adjustments to its proposed expenditure and consequently the costs are reasonably certain.

For these reasons we maintain our draft decision of including the proposed replacement capex relating to SA Water pumping stations in ElectraNet's total forecast capex for the 2013–18 regulatory control period. We restate our recommendation that clause 11.6.11 of the NER be reviewed.

2.5 AER decision

Decision 2.1: table 2.1 shows our final decision on capital expenditure for the 2013–18 regulatory control period.

[290] Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, 18 February 2013, p. 9,
[291] EUAA, *Submission to the AER on Electranet revenue draft determination 2013/14 to 2017/18*, February 2013, pp. 20–1.
[292] NER, clause 6A.8.1(c)(5)(i).
[293] AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 126–8.
[294] 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.
[295] 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.

3 Operating expenditure

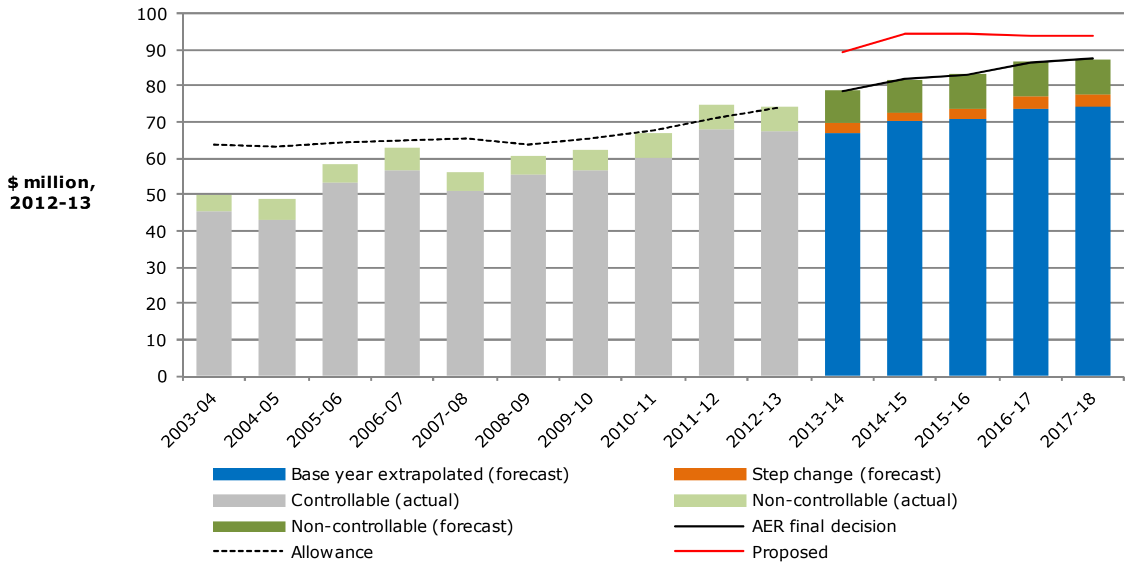
This attachment sets out our final decision, reasoning and approach in assessing ElectraNet's revised proposed operating expenditure (opex) and deriving the substitute forecast for the 2013–18 regulatory control period.

3.1 Final decision

We do not accept ElectraNet's proposed forecast total opex of $466.2 million ($2012-13) for the 2013–18 regulatory control period because it does not meet the opex objectives or criteria.[296] [297] We examined ElectraNet's proposal using different assessment methods which each found ElectraNet's revised forecast opex for 2013–18 is too high.

Our substitute forecast for the 2013–18 regulatory control period is $417.9 million. Figure 3.1 shows our forecast opex (black line) compared with ElectraNet's forecast (red line), is significantly above previous expenditure and the 2008–13 allowance (dotted black line). In percentage terms, our substitute forecast represents a real increase of 23 per cent on actual expenditure in the previous five years, whereas ElectraNet's revised proposal represents an increase of 37 per cent.

Figure 3.1 ElectraNet's total opex: actual, revised proposal and allowance, 2003–18 ($ million, 2012–13)



Source: AER analysis.
Note: 2012-13 is an estimate.

Table 3.1 compares our final decision on total opex with ElectraNet's revised opex proposal.

Table 3.2 shows our opex decision by cost category and Figure 3.2 shows the composition of our opex decision on controllable opex.

296 Unless otherwise stated, all dollars are in 2012-13 mid-year prices.
297 NER, clause 6A.6.6 (a) and (c).

Table 3.1 AER's final decision on total opex ($ million, 2012–13)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
ElectraNet's proposal	89.1	94.3	94.5	94.2	94.2	466.2
AER's decision	78.8	81.8	83.3	86.7	87.3	417.9
Difference	10.3	12.5	11.2	7.5	6.9	48.3

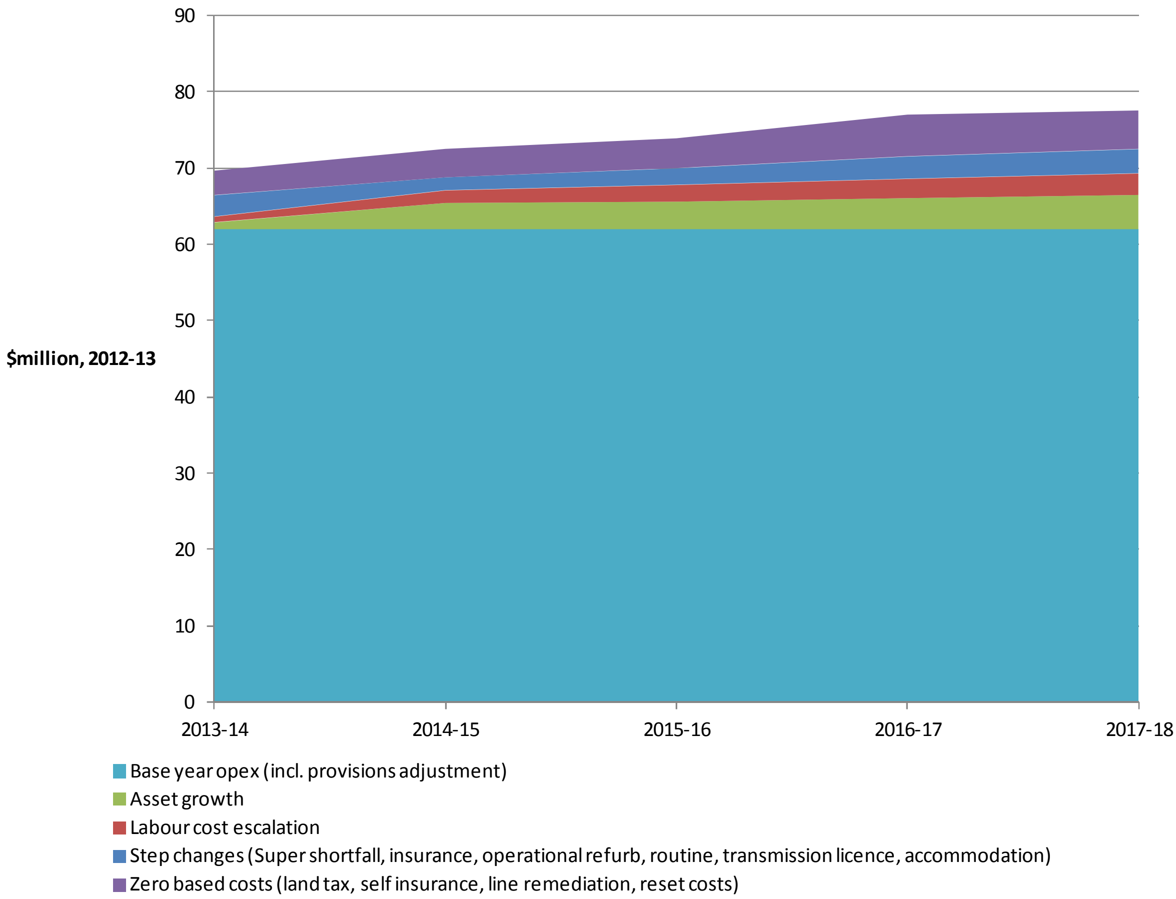
Source: AER analysis.

Table 3.2 AER's final decision on total opex by cost category ($ million, 2012–13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Controllable opex						
Routine maintenance	15.0	15.5	15.7	17.0	17.8	80.9
Corrective maintenance	8.2	8.9	9.0	9.1	9.2	44.3
Operational refurbishment	9.4	9.6	10.2	9.8	9.9	48.9
Corrective maintenance-line remediation	0.8	1.2	1.2	1.2	0.5	4.8
Subtotal: field maintenance	**33.3**	**35.1**	**36.0**	**37.1**	**37.4**	**179.0**
Network operations	8.0	8.2	8.3	8.3	8.3	41.1
Maintenance support	10.3	10.8	10.9	11.1	11.3	54.4
Asset manager support	9.9	10.1	10.1	11.6	11.6	53.2
Corporate support	6.8	7.0	7.2	7.4	7.5	35.8
Self insurance	1.3	1.3	1.4	1.4	1.4	6.8
Total controllable opex	**69.6**	**72.5**	**73.9**	**77.0**	**77.5**	**370.4**
Non-controllable opex						
Network support	8.1	8.2	8.2	8.5	8.6	41.6
Debt raising costs	1.1	1.2	1.2	1.2	1.3	6.0
Total non-controllable opex	**9.2**	**9.4**	**9.4**	**9.7**	**9.8**	**47.6**
Total opex	**78.8**	**81.8**	**83.3**	**86.7**	**87.3**	**417.9**

Source: AER analysis.

Figure 3.2 Composition of AER's final decision on controllable opex ($ million, 2012-13)



Source: AER analysis.

3.2 ElectraNet's revised proposal

ElectraNet proposed a revised forecast total opex of $466.2 million (Table 3.3) for the 2013–18 regulatory control period, which is $11.9 million less than its initial proposal.[298] Of this total, $418.4 million is controllable opex and the remainder is non-controllable opex.[299] The proposed forecast controllable opex is $68.2 million more than our draft decision.

[298] However, when opex is considered with the efficiency benefit sharing scheme, ElectraNet's revised proposal is $0.5 million less than its initial proposal. That is, ElectraNet proposed $465.9 million initially, while its revised proposal was $465.4 million.

[299] Self insurance is a controllable opex item. ElectraNet included it as non-controllable cost item.

Table 3.3 Total opex for 2013–18: ElectraNet's revenue proposal and revised proposal and the AER's draft decision, by cost category ($ million, 2012–13)

Opex category	Revenue proposal	Draft decision	Revised proposal	Revision from initial proposal	
Routine maintenance	80.9	80.9	80.9	No change	Draft accepted
Corrective maintenance	68.8	43.7	68.4	–0.4	
Operational refurbishment	64.9	47.0	66.8	1.9	
Network optimisation	13.3	0	4.9	–8.4	
Sub-total: field maintenance	**227.9**	**171.6**	**221.0**	**–6.9**	
Network operations	47.3	40.2	43.8	–3.4	
Maintenance support	69.9	48.6	53.4	–16.6	
Asset manager support	43.8	51.7	56.7	13.0	
Corporate support	33.8	31.4	36.8	2.8	
Self insurance[(a)]	7.5	6.8	6.8	–0.7	Draft accepted
Total controllable	**430.3**	**350.2**	**418.4**	**–11.9**	
Network support	41.6	41.6	41.6	No change	Draft accepted
Debt raising	6.3	5.8	6.1	–0.2	
Total non-controllable	**47.9**	**47.4**	**47.7**	**–0.2**	
Total opex	**478.1**	**397.6**	**466.2**	**–12.1**	

Note: (a) Self insurance is a controllable opex item. ElectraNet included it as non-controllable cost item in other tables.

Source: AER analysis.

3.2.1 ElectraNet's approach

ElectraNet accepted our draft decision on three opex cost categories: routine maintenance, self insurance and network support.

Top down forecast

ElectraNet used the base year extrapolated approach to forecast some opex cost categories, and it accepted our choice of base year for its support categories.[300] However it submitted revised forecasts for these cost categories because it did not agree with the following elements of our draft decision:

- movements in provisions
- opex efficiency adjustment
- superannuation shortfall payments
- insurance forecast
- asset growth factors

300 The categories are: network operations, maintenance support, asset manager support and corporate support.

- scale efficiency factors
- real cost escalation.

Bottom up/hybrid forecast

ElectraNet did not accept our base year extrapolated approach for forecasting corrective maintenance and operational refurbishment. Instead, it maintained a zero based bottom up build for operational refurbishment and a hybrid approach for corrective maintenance.[301] It regards the risks revealed through its asset condition information as constituting a change in circumstance and therefore the associated opex should be regarded as a step change.[302]

Changes in cost classification for field maintenance

ElectraNet disaggregated its field maintenance cost category into subcategories of routine, corrective and operational refurbishment for its opex forecast for 2013–18. Previously, its actual expenditure, allowance and forecasts (for 2003–08 and 2008–13) were for 'field maintenance'.[303] It recast its actual expenditure for 2003–13 into its new subcategories of field maintenance subcategories, but its regulatory proposals and allowance for 2003–13 were for the aggregate field maintenance category.

During 2008–13 ElectraNet restructured its organisation, implemented a new chart of accounts and realigned its cost centres with its opex allowances. It submitted that these changes have not altered the functional structure of the regulated allowances but have resulted in a revised cost profile across the established regulatory categories (that is, those that we require in the cost information templates and submission guidelines). Accordingly, ElectraNet applied the new cost structure in deriving its revised forecast opex. It changed the classification of its support costs since its previous determination, which made it difficult to compare historical and forecast expenditure.

Increases in opex for demand driven deferrals

ElectraNet adopted a revised demand forecast lower than its original proposal, which led it to defer two substation rebuilds (each with an augmentation component). It proposed these deferrals result in increased operational refurbishment of $2.0 million.

3.3 Assessment approach

We adopted the assessment approach of our draft decision to assess ElectraNet's revised opex forecast. That is, we assessed ElectraNet's revised controllable opex forecast using two methods: a top down forecast based on the base-step-trend method and a detailed bottom up technical review by our technical consultants.[304] We assessed non-controllable opex with a desktop review of ElectraNet's material.

Our approach involved:

- assessing actual efficient and recurrent costs in a reference year (base year)
- adding step changes for new circumstances not captured in the base year expenditure

301 Incoming defect rates were extrapolated.

302 ElectraNet, Revised revenue proposal, p.81.

303 In ElectraNet's 2008–13 revenue proposal, it proposed a bottom up scope change for maintenance projects (which fell within the broader field maintenance category), p. 85. Field maintenance included opex maintenance projects and routine maintenance.

304 ElectraNet's terminology is 'base year extrapolated'. This terminology does not acknowledge the potential for adding step-changes.

- escalating the base costs for real cost escalation and network growth economies of scale factors.

This well established approach to setting regulatory allowances in Australia is fundamental to the effective operation of the incentive regime—specifically, to the interaction of the opex forecast and the efficiency benefits sharing scheme (EBSS) (attachment 12).

We used the top down approach to determine ElectraNet's opex forecasts in our draft decision. For this decision, therefore, our assessment focused on the magnitude and form of any step change adjustments, to ensure the forecast meets the NER opex criteria and objectives.[305] We assessed ElectraNet's revised proposal information on a bottom up basis to satisfy ourselves that ElectraNet has a reasonable opportunity to recover at least efficient costs.[306]

Consultants' review

Energy Market Consulting Associates (EMCa) provided advice on ElectraNet's revised proposal. Its review of the revised proposal focused largely on the asset management framework and implications for field maintenance opex, network optimisation, refurbishment programs (capital expenditure (capex) and opex), the capex–opex trade off and opex efficiencies.[307] We also took into account AM actuaries' case study of ElectraNet's insurance proposal.[308]

Stakeholders' submissions

We received submissions from a number of stakeholders on our draft decision and ElectraNet's revised proposal. We considered these submissions as part of our assessment.

3.4 Reasons for final decision

Our analysis of ElectraNet's opex requirements considers its controllable and non-controllable operating costs. About 90 per cent of ElectraNet's proposed opex is controllable operating expenditure.

3.4.1 Controllable opex

We do not accept ElectraNet's proposed forecast controllable opex of $418.4 million because our review found it to be higher than necessary to meet the opex objectives or criteria.[309] Our substitute controllable opex forecast for the 2013–18 regulatory control period is $370.4 million.

We examined ElectraNet's proposal using two approaches: a top down approach using a base-step-trend method and a detailed bottom up technical review. Both reviews demonstrated ElectraNet's revised proposal was more than required to meet the NER opex objectives. We therefore substituted a forecast using the top down base-step-trend approach, which is a well established top down approach to setting regulatory allowances in Australia. This approach uses actual expenditure in a base reference year which is then escalated for network growth, scale efficiencies and for real costs

305 NER, clause 6A.6.6 (a) and (c).

306 ElectraNet set out that the base-year model will only provide TNSPs with a "reasonable opportunity to recover at least efficient cost" – as set out in the revenue and pricing principles in the National Electricity Law (NEL) – if the resulting forecast of operating expenditure takes account of the forecast variation in operating expenditure over time, compared to the base year (ElectraNet, *Revised revenue proposal 2013–18*, 16 January 2013, p.79). The AER's approach meets the NEL revenue and pricing principles through the step-changes applied to the base year extrapolated forecast such that the substitute forecast meets the NER opex criteria and objectives.

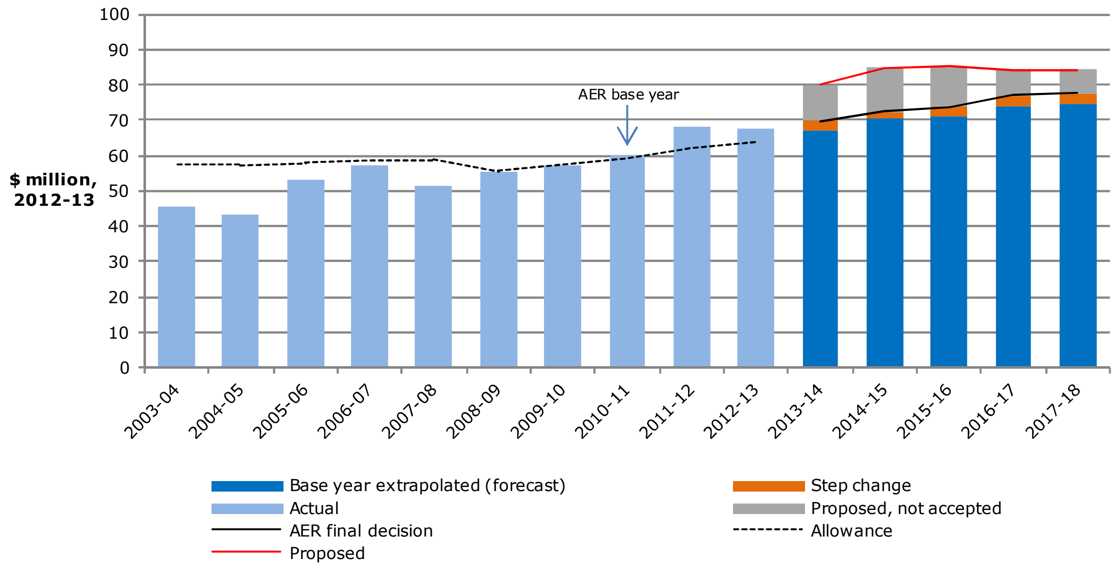
307 EMCA, *ElectraNet technical review - revised revenue proposal*, April 2013.

308 Considered as part of internal policy advice to the AER (February 2013).

309 NER, clause 6A.6.6 (a) and (c).

escalation. We substituted a forecast opex developed from the base year extrapolated method, but we also added some step changes to reflect ElectraNet's changing circumstances.

Figure 3.3 ElectraNet's controllable opex: actual and revised forecast ($ million, 2012–13)



Note: 2012-13 is an estimate.
Source: AER analysis.

Figure 3.3 shows that ElectraNet's revised controllable forecast opex (red line) was significantly higher than our top down assessment (black line) but that our top down assessment is in line with historic allowances (dotted black line) and actual expenditure (light blue bars).

We found no reason to move away from our top down approach, because the incentive framework is predicated on the principle that the revealed actual expenditure is the best indicator of efficient expenditure, and EBSS incentives do not properly work with a bottom up forecast. Our reasons are discussed in our draft decision.[310] ElectraNet's corrective maintenance forecast is a combination of incoming defect rates (extrapolated) and a build-up of backlog defects. ElectraNet's operational refurbishment program is based on packaged works (based on known or predicted defects). In our draft decision we found that ElectraNet's bottom up forecasting method have led it to produce an inflated forecast for its future requirements.[311] These concerns were also expressed by Energy Consumers Coalition of SA (ECCSA) in its submission (February 2013):

> 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 opex assessments from this driver, reduces the value of the incentive program. The ECCSA members all recognise the difference between the two approaches and that a bottom up assessment will inevitably lead to higher claims for opex but a top down approach (as used by the AER) reflects the imperatives of maintaining price competition. The ECCSA considers that the AER is correct to assess future opex on a base year with adjustments basis. The outcome of the AER approach indicates that the opex allowance shows considerable consistency with the actual opex that has been incurred in the past.[312]

ElectraNet's actual expenditure on defects is a better indicator of efficient costs than is an incoming defect rate (ElectraNet's forecast method) because actual expenditure has been realised through a

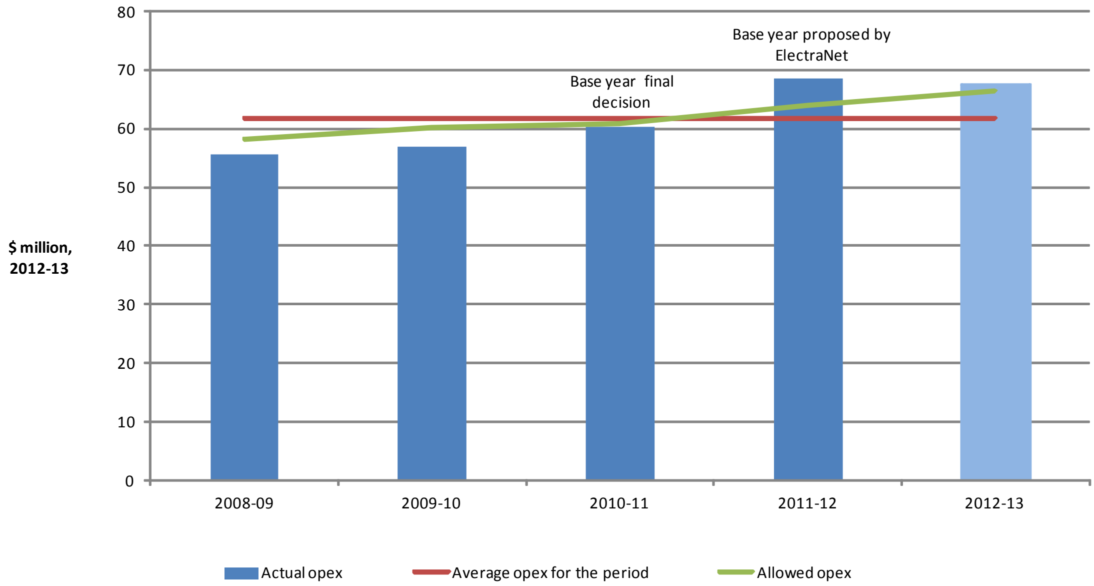
[310] AER, *Draft decision: ElectraNet transmission determination, November 2012*, pp.150-152.
[311] AER, *Draft decision: ElectraNet transmission determination, November 2012*, pp.150-152.
[312] ECCSA, *Submission on ElectraNet's revenue proposal for 2013-18*, (February 2013), p.21.

risk assessment and prioritisation process and within ElectraNet's budget constraints.[313] ElectraNet's incoming defect rates are presented as numerical inputs to its asset management framework. They are assigned a risk assessment code, and prioritised along with inputs from the financial plan and network risk profile. The outputs of the asset risk prioritisation process are the prioritised planning profile and the prioritised work schedule. Using the incoming defect rate as a basis for the forecast expenditure separates the inputs of the framework from the prioritisation assessment process and financial plan (outputs). In contrast, the actual expenditure in the base year (our method) has been through the whole process and incorporates any iterative/feedback parts of the prioritisation loop.

Base year

We consider the base year should be a year in which expenditure was efficient and reflective of ongoing recurrent costs and likely prevailing economic conditions. We thus used the actual expenditure in 2010–11 as the reference for the base year because the actual controllable expenditure closely represents average expenditure for the whole regulatory period for all opex categories (Figure 3.4.).[314] [315] ElectraNet accepted this as a base reference year.[316]

Figure 3.4 Controllable opex actual compared with allowance 2008–13 ($ million, 2012-13)



Source: AER analysis.

[313] ElectraNet, *Asset management plan*, pp.109-110.

[314] In its February 2013 submission, the EUAA agrees with the AER that Electranet's proposed base year 2011-12 is not appropriate, but is "not convinced that 2010-11 is necessarily the right answer either". It suggests that the AER averages the opex for all years in the current regulatory period for which audited actual data is available, in setting the base year for the opex allowance for the next control period. The EUAA notes Electranet's annual opex "seems to exhibit some significant inter-annual variance and the choice of an average of the outcome in the regulatory period would seem to be an appropriate way to deal with this uncertainty". The AER is considering its assessment approach in its development of expenditure guidelines in its Better Regulation work program.

[315] AER, *Draft decision: ElectraNet transmission determination, November 2012*, pp.149-152; pp.281-283.

[316] For the categories of expenditure which it agreed were base-year-extrapolated. ElectraNet comments that the AER was incorrect in changing the base year because of the lumpy nature of corrective maintenance and operational refurbishment and referred to Figure 7-1 in [ElectraNet's] revised application to demonstrate this. ECCSA responded to this point in its submission [ECCSA, *Submission on ElectraNet's revised proposal for 2013-18,* February 2013, pp. 21-22] by demonstrating that on average and in aggregate ElectraNet has managed its business within allowance. The AER's top down approach focuses on the average trend requirements, and the framework allows the TNSP discretion to manage its allowance within the five year regulatory period. We matched our top down assessment with a bottom up assessment to account for specific step change requirements and step changes can address the issue of lumpiness and annual variation.

After we determined ElectraNet's base year costs, we made necessary adjustments to the base year expenditure to ensure it is efficient and reflective of recurrent costs. For example, we made an adjustment for the movements in provisions.

Movement in provisions

In our draft decision, we applied a decrement of $0.4 million to ElectraNet's base year opex to reverse the movement in provisions for future employee entitlements. In its revised proposal, ElectraNet did not accept our draft decision. It noted it is required to account for employee entitlements according to the Australian Accounting Standards.[317]

We recognise employee entitlements are appropriately recorded in a provisions account as they are accrued, consistent with standard accounting practice. However, we consider a provision should be distinguished from other liabilities because the timing and amount of the future expenditure required in settlement are uncertain. A liability for an employee entitlement such as annual leave, long service leave or superannuation is accrued some time (even a long time) before it is paid. Whether particular expense provisions will materialise in the future may also be uncertain. Given these uncertainties, it is more appropriate to consider such costs as they are incurred, not as liabilities accrued for opex forecasting purposes.

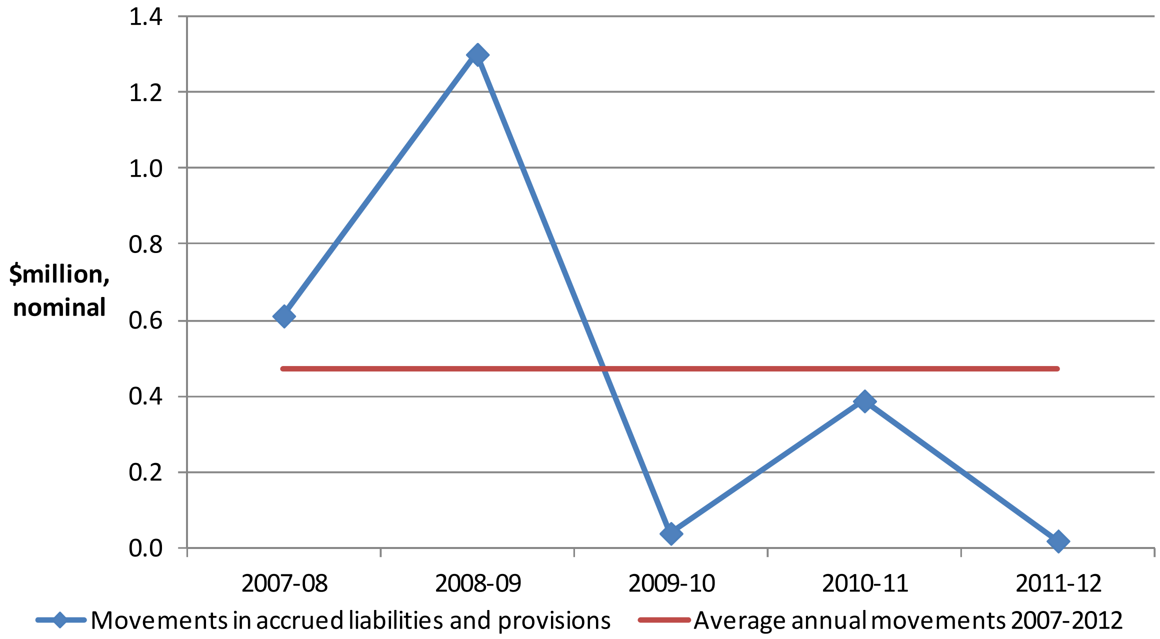
ElectraNet's accounting system may help us determine efficient costs in the base year. However, in forming our views on provisions related costs, we also had regard to the treatment of such costs in the context of Australian taxation law. As discussed in attachment 5, both the *Income Tax Assessment Act 1997* (ITAA97) and the High Court decision provide that employee leave entitlements is not incurred until such time as the actual leave is taken, at which time the liability to pay would be paid and thereby 'incurred'. [318] [319]

For these reasons, we consider provisions accrued in a given year do not represent actual costs incurred in that year and should be removed from base year expenditure. However, we do recognise cash paid out for the expenses to which the provisions relate, by reversing the movements in provisions in the base year.

Figure 3.5 shows ElectraNet's movements in provisions are positive for each year of the period 2007–08 to 2011–12—that is, the amount of accrued provisions were more than actual cash paid out for provisions for each year. The movement in provisions in the base year (2010–11) amount was $0.4 million, which is relatively close to the average value of the period ($0.5 million). Consistent with our draft decision, we reduced the base year opex by $0.4 million to reverse the movement in provisions. We consider this adjustment will result in a forecast total opex that reasonably reflects future expected costs incurred for employee entitlements.

[317] ElectraNet, *Revised revenue proposal*, p.110.
[318] Australian Tax Office, TR2011/6
[319] *Nilsen Development Laboratories Pty Ltd and Ors v Federal Tax Commissioner* (1981) 33 ALR 161

Figure 3.5 ElectraNet's movements in provisions, 2007–08 to 2011–12 ($ million, nominal)



Sources: ElectraNet, Response to information request AER/RP011, ENET239, p. 3; AER analysis.

Step changes and other adjustments

After we determined ElectraNet's efficient and recurrent base year costs, we add step changes for new requirements.

Our substitute forecast controllable opex allows for an additional $17.5 million ($2012–13) above the base year extrapolated trend for step changes. The step change in the field maintenance category is $14.9 million.[320] The step changes and other adjustments we approved are set out in Table 3.4.

Having determined the base opex, our assessment approach is to recognise TNSPs may be subject to changes in regulatory obligations or operating environment that are not reflected in the recurrent expenditure of the base year. For this reason, the base opex should be adjusted for costs arising from new (or changed) legislative obligations or a change in operating environment. These are termed 'step changes'. When a proposed step change is driven by an exogenous factor (for example, a legislative change in safety or environmental compliance regulation, a tax change event or a change to the TNSP's transmission authority), our assessment is relatively straightforward. However, our assessment is more difficult when a proposed step change is driven by an endogenous factor. Endogenous drivers, such as a management decision to adopt a new asset management expenditure strategy, can result in windfall gains through the EBSS, and possibly other unintended outcomes. In these circumstances, we must consider the timing and form of the step change—that is, whether it is a one-off cost, or whether it represents a new ongoing change to the steady state base level. On this matter, the Energy Consumers Coalition of South Australia (ECCSA) adds that:

> Unless the effect of the EBSS is reflected in future opex allowances, then the purpose of incentive regulation is being marginalized. The ECCSA notes that its affiliates have recognized similar approaches

320 However, these step changes are in addition to the incremental: condition monitoring costs, backlog corrective maintenance costs, routine maintenance costs and other implementation costs that occurred in 2010-11 and were thus trended in the base-year-extrapolation methodology (therefore included in our forecast as 'base-year' costs).

> used by other regulated firms – that they seek the benefits of the EBSS yet consistently seek to have some or all of their future opex allowances developed from a bottom up approach rather than using the revealed outcomes from that have been subject to incentives. (ECSSA, Submission on ElectraNet's revised proposal. The ECCSA is of the view that actual outcomes, moderated by step changes and cost escalation and growth, provide a much better basis for setting future allowances than using new bottom up assessments. This reflects what occurs in firms subject to competition when setting future prices for their services and products.[321]

ElectraNet regards the risks revealed through the asset condition information flowing from its implementation of its enhanced asset management regime as constituting a change in circumstances, and contends the associated opex should be regarded as a step change.[322] [323] In forming our decision on the amount and form of the step change (if any) required, we considered EMCa's detailed bottom up technical review of ElectraNet's revised revenue proposal (section 3.4.3).

321 ECCSA, *Submission on ElectraNet's revised revenue proposal and AER draft decision*, February 2013, p.23.

322 ElectraNet, *Revised revenue proposal*, January 2013, p.81.

323 ElectraNet says the AER's contentions (from the draft decision) that ElectraNet is operating in a steady state environment are at odds with its earlier acceptance in the AER's determination for 2008-13, in which the AER accepted that ElectraNet was in the process of introducing the new asset management regime. ElectraNet refers to the AER's consultant, SKM as having noted that actual opex in the relevant base year was insufficient to provide a sustainable and efficient operation. [ElectraNet, *Revised revenue proposal*, February 2013, p.82]. On this matter we considered EMCa's advice [EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, pp. 32-35, paragraph 134–147]. See section 3.4.3 for detailed discussion.

Table 3.4 AER's approved step changes and other adjustments ($ million, 2012-13)

Cost category	Reason for step change / adjustment
Routine maintenance	We accept ElectraNet's routine maintenance forecast of $80.9 million, which is effectively a step change increase of $9.0 million. ElectraNet's asset management framework and approach may facilitate asset lifecycle management of risks in a transparent and cost effective manner. An increase in routine maintenance should result in reduced corrective maintenance and deferred asset replacement.
Operational refurbishment	We accept a step change of $1.0 million for operational refurbishment works because ElectraNet adopted a revised demand forecast methodology which has deferred substation replacement projects (with augmentation components) at Kingcraig and Keith substations.
Network optimisation (corrective maintenance)	We accept ElectraNet's proposed $4.9 million to remediate high risk low hanging transmission line spans. We categorised this cost as corrective maintenance for line remediation. It is a one-off step-change which should be excluded from ElectraNet's future opex forecast beyond 2018.
Support categories	We added step changes for insurance and defined benefits, transmission licence fee (step change decrement) and new lease step changes are included in this category. The total net step increase is $12.9 million but the line items are discussed below.
Insurance	We accept ElectraNet's proposed insurance forecast meets the opex criteria and objectives. We added the difference of $2.4 million as a step change to the base year extrapolated allowance.
Defined benefits liability	We accept a step change of $2.4 million for ElectraNet's unfunded superannuation liabilities (the shortfall in defined benefits) which have increased in the current market environment, and it faces a change in its operating environment due to exogenous factors. In support, ElectraNet submitted a letter from the Electricity Industry Superannuation Scheme (Scheme) setting out the level of contributions that ElectraNet was required to pay to cover the shortfall in defined benefits.[324] These contributions were based on recommendations in an independent actuarial report to the Scheme from Mercer Consulting.[325] In light of this additional material we approve ElectraNet's proposed $2.4 million to cover the shortfall in defined benefits.
Transmission licence fee	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 2013–18. We reduced ElectraNet's proposed opex forecast by $2.4 million accordingly.
New lease	We added ElectraNet's office accommodation costs to the base year. The impact of the step change after escalation was $1.0 million.
Movement in provisions	We applied a decrement of $0.4 million to ElectraNet's base year opex to reverse the movement in provisions for future employee entitlements. This was an adjustment to the base year and the impact of the adjustment after escalation was $2.0 million (decrement).
Land tax	We accept ElectraNet's revised land tax forecast of $13.0 million, which is $1.2 million more than our draft decision. The increased forecast reflects our final decision to approve more of ElectraNet's proposed strategic land purchases than we did in our draft decision. This is a zero-based adjustment.

Source: AER analysis.

Trend for network growth and real cost escalation

As part of forecasting ElectraNet's opex requirements we take into account network growth and other factors that lead to cost increases. We do this by escalating ElectraNet's base year opex. Table 3.5 shows the impact of AER escalation on controllable opex.

324 Electricity Industry Superannuation Scheme, letter to ElectraNet, 16 April 2012, [Confidential].

325 Mercer Consulting (Australia) Pty Ltd, *Report to the Electricity Industry Superannuation Board and ElectraNet*, 4 April 2012, [Confidential].

Table 3.5 Impact of AER escalation on controllable opex ($ million, 2012–13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Base year opex (incl. provisions adjustment)	62.0	62.0	62.0	62.0	62.0	310.2
Step changes and other adjustments	2.9	2.3	2.8	2.4	2.1	12.5
Labour cost escalation	0.7	1.6	2.2	2.5	2.8	9.9
Asset growth	0.9	3.4	3.6	4.1	4.5	16.4
Zero based costs (land tax, self insurance, line remediation, reset costs)	3.2	3.7	3.9	5.5	5.1	21.4
AER's final decision	69.7	73.2	74.6	76.5	76.5	370.4

Source: AER analysis.

Asset growth

As ElectraNet’s network grows it will incur increasing operating costs but it will also be able to achieve some economies of scale.

We accept ElectraNet's revised method for forecasting asset growth factors. However, we have updated the asset growth factors to reflect our final decision on ElectraNet's load driven capex forecast, as discussed in attachment 4. In our draft decision, we did not approve ElectraNet's method for estimating asset growth because the TNSP's proposed asset growth factors reflected depreciated regulated asset vase (RAB) value. We considered an undepreciated RAB value should be used for estimating asset growth. In its revised proposal, ElectraNet adopted our method, using the undepreciated RAB value determined in our draft decision. However, it updated the asset growth factors to reflect its revised capex.

Energy Users Association of Australia (EUAA) submitted that opex should not be escalated based on RAB escalation, because Electranet proposed relatively low expenditure on network augmentation and relatively more asset replacement and therefore the driver of RAB growth is due mainly to asset replacement. The AER recognises this issue for replacement capex and have used the replacement value for estimating asset growt in our decision.

In relation to EUAA’s comment that AER should develop and index: [326]

> In general new assets will have a lower maintenance and operational expenditure requirement than the old assets that they replace. This should therefore result in a decrease in the allowance for opex, not an increase. To the extent that any allowance is to be made for increased opex as a result of increased network capacity, we suggest that the AER develops on index that accounts for changes in network length and transformation capacity.

EUAA submissison that the AER develop an index to calculate increased opex in relation to the increased network capacity will be taken into consideration in determinations where augmentation capex is part of the revenue determination.

[326] EUAA, *Submission on Electranet 2013 to 2017 revenue determination,* 19 February 2013, p. 17.

Economies of scale

We adopt the same economies of scale factors as those used in ElectraNet's 2008–13 transmission determination. ElectraNet proposed increasing some scale factors indicating it would become less efficient with network growth. ElectraNet has not provided reasons why it cannot maintain its existing economy of scale efficiencies and would expect to become less efficient. However, we accepted direct charges should be applied at 100 per cent.

ElectraNet's proposed asset growth factors incorporate economies of scale factors, because asset growth does not result in a one-for-one increase in opex for all operating cost categories. ElectraNet proposed to increase 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. We uphold our draft decision not to accept ElectraNet's proposed changes to its economies of scale factors, because we are not satisfied that the TNSP's reason for changing the scale factors is sufficient to demonstrate the proposed opex forecast is a realistic expectation of cost inputs:

- The proposed changes mean ElectraNet expects to become less efficient in 2013–18 than in 2008–13 in its network operations and asset manager support categories. The reason it expects to become less efficient in these categories is based on its 'experience and judgement'.[327] We consider this reason does not meet the opex criteria.
- ElectraNet considered the scaling factors applied in its proposal are reasonable and relatively conservative. It submitted that the characteristics of its operating environment—including small network scale, low customer density, low load factors and unique topology compared with other TNSPs—mean it is more challenging for ElectraNet than some TNSPs to drive further scale efficiencies.[328]
- While ElectraNet highlighted the difficulty of 'driving further scale efficiencies', we consider ElectraNet can still reasonably maintain its existing scale efficiencies. ElectraNet's proposal, however, suggested it is becoming less efficient. It did not explain why it cannot maintain its existing economy of scale efficiencies and why it expects to become less efficient in these areas.

In our draft decision, we concluded 'ElectraNet is unlikely to be less efficient in the future than currently and applied the same factors used for the current regulatory period for each cost category, with the exception of direct charges'.[329] We accept ElectraNet's comments that direct charges should be applied at 100 per cent. We maintain our draft decision that no reason exists to change the economies of scale factor applied to the maintenance support category from that applied in 2008–13. Except for direct charges (which have a factor of 25 per cent as determined in our draft decision, but which should be 100 per cent), we applied an economy of scale factor of 25 per cent to the remainder of maintenance support costs.

Real cost escalation

Forecast opex should provide for future input cost increases. We achieve this by applying real cost escalators to base year operating expenditure. As outlined in attachment 1, we did not accept ElectraNet's proposed real cost escalators but applied lower escalators which reduces ElectraNet's total opex requirements.

[327] AER, *Draft decision: ElectraNet transmission determination, November 2012*, p.153.
[328] ElectraNet, *Revised revenue proposal*, p. 115.
[329] AER, *Draft decision: ElectraNet transmission determination, November 2012,* p. 153.

3.4.2 Non-controllable costs

ElectraNet has two types of non-controllable opex costs, debt raising costs and network support.

Debt raising costs

Our draft decision accepted ElectraNet’s proposed method for determining its benchmark debt raising costs allowance associated with its forecast opex.[330] We consider this method provides estimates of the debt raising costs that a prudent service provider acting efficiently would incur, because it:

- identifies the types of transaction cost that a prudent service provider acting efficiently would incur in raising debt
- quantifies the level of these costs (using benchmark assumptions that also account for the circumstances of the service provider) with reference to market rates for the relevant services.

We updated ElectraNet's proposed debt raising cost allowance to reflect our final decisions on the opening RAB (debt component) and weighted average cost of capital (WACC). Our final decision, therefore, is to provide ElectraNet with an allowance for debt raising costs of $6.0 million ($2012–13), as shown in Table 3.6.

Table 3.6 AER's final decision on debt raising costs ($ million, 2012–13)

Unit rate	2013–14	2014–15	2015–16	2016–17	2017–18	Total
9.2 basis points per year	1.1	1.2	1.2	1.2	1.3	6.0

Source: AER analysis.

Network support

We accepted ElectraNet's proposed allowance of $41.6 million for network support for the 2013-18 regulatory control period as set out in our draft decision. 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.[331] 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.

3.4.3 Technical review

We engaged EMCa to advise on ElectraNet's controllable opex proposal and revised proposal. EMCa's technical review of ElectraNet's initial proposal showed ElectraNet’s controllable opex forecast, was higher than the forecast that EMCa considered reasonable. EMCa recommended ElectraNet's initial proposal be reduced by about $63.2 million.[332] EMCa's technical review of ElectraNet's revised revenue proposal showed ElectraNet's revised controllable opex forecast was still higher than the forecast that EMCa considered reasonable. EMCa's recommendations guided our assessment of the amount and form of the step changes to be added to the base year extrapolated forecast so the allowance reasonably reflects the NER opex criteria and opex objectives.[333]

330 AER, *Draft decision: ElectraNet transmission determination, November 2012,* pp. 162–3.

331 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].

332 EMCA, *Technical review*, 30 November 2012, p. 29; This recommendation assumed ElectraNet's real cost escalation, but did not accept the premise of the escalation inputs.

333 NER, clause 6A.6.6 (a) and (c).

The focus of EMCa's bottom up review of ElectraNet's revised opex proposal was:

- asset mananagement and its implications
- routine maintenance opex
- corrective maintenance opex
- refurbishment opex
- network optimisation
- opex efficiency factor
- capex–opex trade off: costs and benefits

In summary, EMCa observe that ElectraNet has largely provided similar information to what was provided in the initial revenue proposal, with limited or no further primary analysis.[334] In most instances, the information helped EMCa confirm it had not misunderstood ElectraNet's original proposal and has allowed it to confirm the substance of its findings.

Asset management and its implications

Having reviewed ElectraNet's revised proposal, EMCa maintained its view that ElectraNet's asset management framework represents good industry practice in principle. However, EMCa still had concerns about how ElectraNet implemented the framework and whether ElectraNet was maximising the potential benefits of the framework. EMCa's view remains that development of the mechanisms for asset strategy optimisation are not yet mature and may not be producing appropriately optimised asset management plans.[335] EMCa found that ElectraNet has not provided sufficient evidence to support its implementation in the form of a business case in accordance with good expenditure governance and setting out:[336]

- the full incremental costs of the implementation
- consideration of deployment options, including sampling, different means of collecting condition data, "fix now while on-site" versus "fix later" options for minor corrective work and specific analysis and consideration of major expenses within the program (such as aerial survey work)
- A clear and convincing statement of the expected benefits for various aspects, in excess of the costs of implementation, and including an action plan and monitoring program to enable assessment of the benefits and redirection of the program if/as required during the deployment
- Convincing evidence that the comprehensive asset data that has been collected is being fully utilised when prioritising asset management tasks and making expenditure decisions
- A resulting pattern of lower forward capex or opex costs, with timings.

It appears that ElectraNet's transition to the enhanced condition-based asset management framework has and will be a major driver of opex requirements. EMCa expressed the following concerns:

> EMCa agrees with ElectraNet's view that the use of condition-based maintenance in determining maintenance needs and replacement needs is good industry practice. That said, ElectraNet has

334 EMCa *ElectraNet technical review – revised revenue proposal*, April 2013, p.2, paragraph 5

335 EMCa *ElectraNet technical review – revised revenue proposal*, April 2013, p.27, paragraph 105.

336 EMCa *ElectraNet technical review – revised revenue proposal*, April 2013, p.27, paragraph 106.

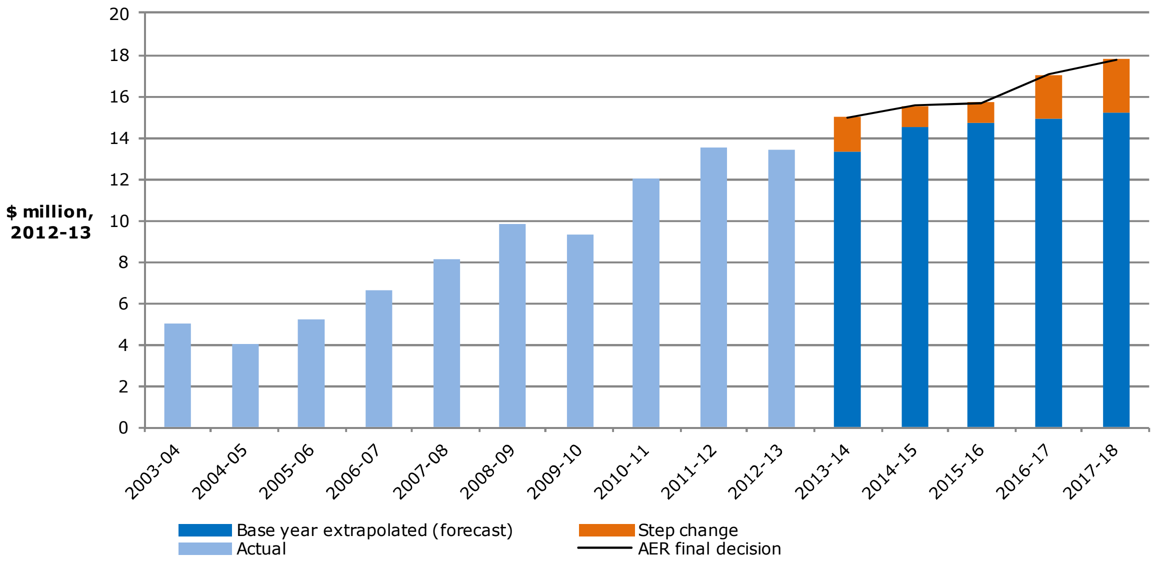
introduced comprehensive condition-based maintenance in a manner that may not be optimal in matching project benefits to project costs. In our view this is likely to be because, without a firm business case, ElectraNet has paid insufficient attention to the expected benefits. There is a lack of evidence that either costs or benefits have been adequately considered prior to or during the implementation of this program. Comprehensive condition-based maintenance is expensive to implement due to the high cost of data collection and analysis. Such a comprehensive approach has traditionally been implemented in industries where there is a very low tolerance for failure and the large costs of implementing and operation are offset against unacceptable or very large costs of failure (for example, in the airline, nuclear, and military equipment industries). ElectraNet appears to have fully implemented its model without adequately articulating the specific management strategies that are likely to arise from its use.[337]

We accept most of EMCa's analysis and reasoning set out in chapter 4 of its April 2013 report. We discuss in further detail the implications of EMCa's findings on this matter to our final decision in the capex–opex trade off section.

Routine maintenance

In our draft decision, we accepted ElectraNet's proposed forecast for routine maintenance of $80.9 million. The forecast is a $9.0 million step change increase on the revealed cost trend line (Figure 3.6).

Figure 3.6 ElectraNet's routine maintenance ($ million, 2012–13)



Source: AER analysis.

We accepted the proposed routine maintenance forecast because we:

- support the principle of the condition based maintenance approach. The asset management framework that ElectraNet has begun to deploy may, in principle, facilitate lifecycle management of risks in a transparent and cost effective manner.
- accept ElectraNet's reasoning that an increase in routine maintenance expenditure should result in benefits in other field maintenance areas, such as reducing corrective maintenance opex and lowering overall total asset lifecycle costs by deferring replacement capex.

337 EMCa *ElectraNet technical review – revised revenue proposal*, April 2013, p. 24, paragraph 92-93.

- recognise that ElectraNet committed to condition assessments in advance of the 2008–13 regulatory control period (as part of its revenue proposal in 2007), and the routine maintenance plans (which incorporate ongoing condition assessment)[338] are well established.

Corrective maintenance

We do not accept ElectraNet's revised corrective maintenance forecast of $68.4 million meets the opex objectives. We substitute a forecast of $49.2 million; which is based on ElectraNet's actual expenditure in the base year, extrapolated for network growth and real cost escalation ($44.3 million) plus a step change of $4.9 million for line sag remediation works. [339] In our draft decision we set out our findings that ElectraNet's corrective maintenance forecast does not reasonably reflect efficient costs because ElectraNet's method overestimated its future expenditure requirements. We were not satisfied that ElectraNet had demonstrated a step-change to its base expenditure was required to meet the opex objectives to maintain the reliability of its network.[340]

ElectraNet proposed $23 million for corrective maintenance of substations and $40 million for corrective maintenance of transmission lines. The costs were to cover a backlog of already identified defects and a base level of assumed incoming defects.[341]

In our draft decision, we considered that 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. We noted ElectraNet is only partly 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. ElectraNet did not agree with our draft decision and did not accept the substituted forecast; its revised forecast was the same as its initial proposal.

Figure 3.7 shows ElectraNet's corrective maintenance opex forecast and the AER's final decision.

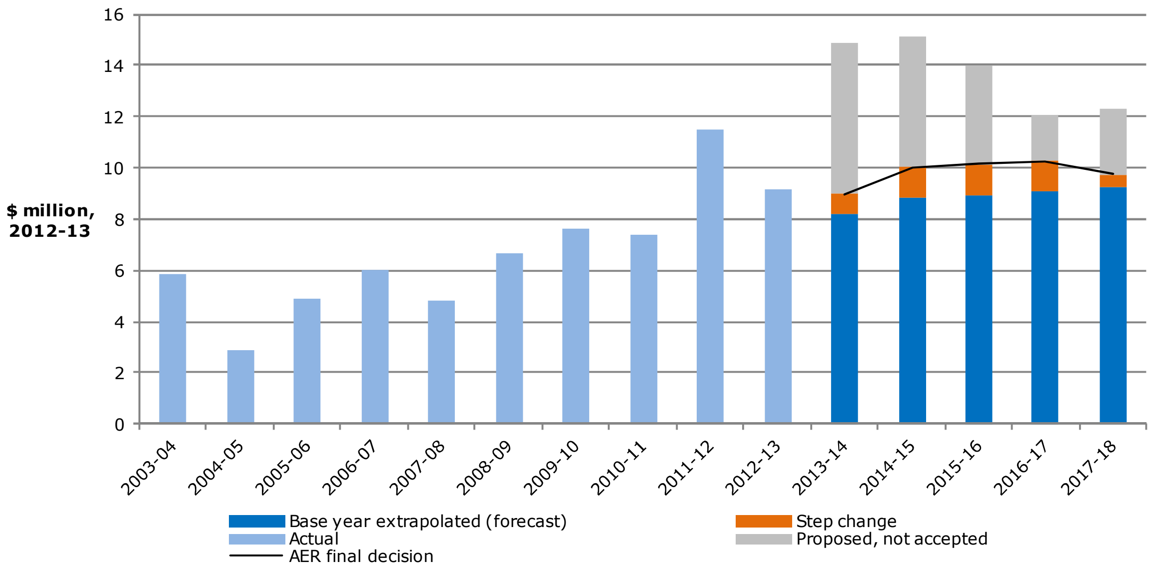
338 For substations in entirety and partly for transmission line assessments.

339 The total includes a one-off step change of $4.9 million for line sag remediation works which is discussed in the network optimisation section.

340 NER, clause 6A.6.6(c).

341 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p.157.

Figure 3.7 ElectraNet's corrective maintenance ($ million, 2012–13)



Note: The step change is for line remediation (proposed as network optimisation) which we reclassified. This is discussed under the network optimisation subheading.

Source: AER analysis.

We accept ElectraNet's assurance that non-deferrable high risk defects included in the corrective maintenance forecast cannot be deferred, but consider that ElectraNet's forecast does not meet the NER opex criteria because it does not account for the expected reduction in identified defects. A reasonable corrective maintenance expenditure forecast would take the expected reduced rate of defect identification into account.

The base-year extrapolated forecast will provide ElectraNet with the ability to manage its backlog of defects over the forthcoming period. The total active number of defects (backlog) should reduce as the incoming rate of defects declines over time. To use the incoming defect rate as a basis for the forecast expenditure (as ElectraNet has) separates the inputs of the asset management framework from the prioritisation assessment process and financial plan (outputs). In contrast, the actual expenditure in the base year has been through the whole process and incorporates any iterative/feedback parts of the prioritisation loop.[342]

EMCa's review of Electranet's proposed expenditure in the context of its historical expenditure and condition assessment cycles is set out in section 4.3.3 of its April 2013 report.[343] In EMCa's review, it observes that during 2008–13, ElectraNet overpent by nearly 40 per cent ($12 million) relative to its corrective maintenance allowance. ElectraNet explained this variance was to address critical risks as they were identified (mostly in regards to lines, and including fire start risks),[344] as well as incurring new spending on aerial line surveys. ElectraNet provided examples of its large overspends incurred on urgent and unscheduled correction, resulting from risk reprioritisation of available resources from operational refurbishment activites.[345] EMCa note that therefore, the step change for corrective maintenance contemplated for 2013–18 comes on top of a considerable step change in actual corrective maintenance spending.[346] EMCa reviewed the composition of the defects[347] and considers:

342 ElectraNet, *Asset management plan*, pp.109-110.

343 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, pp. 32-35, paragraphs 132-144.

344 ElectraNet, *Revised revenue proposal*, p.76.

345 ElectraNet, *Revised revenue proposal*, p.82.

346 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, pp. 32-33, paragraph 134.

> the defects now being identified through a more structured information-collection program are unlikely to have just arisen .... they are of the same nature as defects previously arising and being managed under ElectraNet's previous maintenance regime.[348]

> Condition data for substations (where the data set is 100 per cent complete) and transmission lines (where the data set is 40 per cent complete and represents a substantial sample of the population of lines) has been collected yet the benefits of the correction of defects found from this significant assessment do not appear to have been factored into future corrective maintenance schedules for substations or transmission lines.[349]

Incoming defect rate

As we set out in our draft decision, we expect the incoming rate of defects should reduce as the cycle progresses—as high risk defects identified in the first cycle are rectified, the incoming trend will be towards defects with lower risk / longer timeframes. We consider it reasonable to expect that the level of defects detected will reduce in subsequent cycle inspections due to the work already undertaken in addressing defects.[350] For this reason, an average incoming defect rate is not a reliable indicator of future incoming defect rates and ElectraNet's forecast does not sufficiently account for this declining rate.

ElectraNet assumed the identified defects will reduce by 20 per cent in the second pass, but EMCa regarded this to be a very conservative assumption.[351] In EMCa's opinion, it is more likely that the defects identified will reduce to 20 per cent and that a conservative middle ground is a further 20 per cent reduction in line with our draft decision.[352] Our analysis of ElectraNet's incoming number of defects from June 2010 to February 2013 shows that the linear trend rate for the number of incoming defects for substations declined by 33 per cent in the 33 months of data presented.[353] These results support EMCa's observation that ElectraNet has overestimated its base level of incoming defects.

For transmission lines, the condition assessment cycle is at an earlier stage, so ElectraNet's time trend for incoming defects does not yet show a downward trend. About 45 per cent of all transmission line assets have been assessed.[354] ElectraNet used the average incoming defect rate for June 2010 to June 2012[355] as the basis for its forecast, but then updated the data to February 2013.[356] This suggests the high priority and more costly risks from the first pass were used to forecast an ongoing base level.[357] Once the first cycle is complete, the incoming rate of defects should exhibit a downward trend in corrective maintenance defects. EMCa observed that transmission lines are less complicated than substations, meaning it would be unlikely that high and medium risk defects found on lines would continue to be found at the same rate as on the first inspection.[358]

347 EMCa, *ElectraNet technical review – revised revenue proposal, Appendix 7*, April 2013, pp. 116-118, paragraph 438-445; ElectraNet, *Email response to information reques t- Defect Noti Incoming Rate Volume since 01/06/2010,* ENET357.
348 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.33, paragraph 135.
349 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.33, paragraph 136.
350 The first round of substation assessments was complete before 2008.
351 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 34, paragraph 142
352 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 34, paragraph 142.
353 AER analysis based on ElectraNet, *Email response to information request EMCa069 - Corrective maintenance*, ENET354 [Confidential].
354 ElectraNet, Asset Management Plan.
355 ElectraNet, *Email response to information request EMCa 046 - Asset condition and corrective maintenance*, ENET211 [Confidential].
356 AER analysis based on ordinary least squares linear trend and the average incoming defect rate increased by about 9 per cent.
357 ElectraNet noted that it focused its first 30 per cent on the highest risk lines, ElectraNet, *Email response to information request EMCa 046 - Asset condition and corrective maintenance*, ENET211, p. 6 [Confidential].
358 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p. 34, paragraph 140.

ElectraNet acknowledged that it does expect a declining rate of incoming defects over time,[359] it submitted that the reduction in defect rates will be offset by an increase in defects seen on newly purchased, installed and commissioned equipment.[360] We do not accept this argument because:

- ElectraNet provided no supporting evidence that a decreasing trend in incoming defect rates is offset by a commensurate increase in spending on early faults in new equipment.[361]
- ElectraNet pointed to secondary systems failure as the most common cause of new equipment failure. EMCa regards these failures as typically easily corrected and generally tending not to have such large consequential costs. EMCa suggests this type of costs may arguably come under operational maintenance budgets rather than the corrective maintenance budget.[362]
- Much of the primary infant mortality costs would be at the expense of the manufacturer or contractor and ElectraNet's insurance and self insurance policies indicate some of the infant mortality costs may be covered by these policies (if not by manufacturing warranties).[363]
- Increasing front-end costs would depend on the rate of introduction of new equipment and would be separate from trends in incoming defect rates.[364]

These infant mortality effects are generally associated with the introduction of a new product or model, which undergo an early life cycle discovery phase that identifies design and new component issues. The construction of a standard design substation from commonly used components is very different to the introduction of new product lines and would be expected to have failure rates on the stable midpoint on the curve. EMCa do not expect an organisation such as ElectraNet to be purchansing untried and untested equipment.[365]

Back log of defects

ElectraNet proposed additional corrective maintenance to clear a backlog of defects. However, we consider the base year forecast already provides for ElectraNet to efficiently manage its backlog. This is because ElectraNet's 2008–13 allowance included a one-off allowance to clear substation maintenance backlogs. Our forecast, which allowed for the substation backlogs in the expenditure of the base year, can now be allocated by ElectraNet to address its identified transmission line backlog. EMCa considered ElectraNet's aim to entirely eliminate its backlog of defects to be unrealistic and unnecessary and is a more aggressive strategy than it is currently applying. Further, we consider ElectraNet has overestimated its forecast corrective maintenance costs because it overestimated its incoming defect rates which should decline over time. The incoming rate of defects should reduce as high risk defects identified in the first cycle are rectified, leaving lower and less urgent risks to be corrected.

EMCa's review of the revised proposal recommended we maintain our top down approach and not apply a step change. That is, EMCa considered the base year extrapolated approach of our draft decision a reasonable method to forecast the corrective maintenance effort required for prudent maintenance of these assets. It found that, on balance, the evidence from ElectraNet indicates it has

359 ElectraNet, *Email response to information request EMCa069 - corrective maintenance*, ENET354, p. 4 [Confidential].
360 ElectraNet, *Email response to information request EMCa069 - corrective maintenance*, ENET354, p. 4 [Confidential].
361 ElectraNet sets out that it has extended warranties on individual high capital value items and defect liability to cover faulty or poor quality workmanship, ElectraNet, *Revised revenue proposal*, pp.92-92.
362 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 35, paragraph 145.
363 ElectraNet included forecast insurance premiums in its opex forecast to cover: commercial insurance for substation machinery breakdown and equipment failure; and a self insurance allowance for below deductibles for substation machinery breakdown and line failure. ElectraNet, *Revenue proposal – Appendix V, Aon risk solutions - Self insurance risk quantification*, p. 8.
364 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 35, paragraph 145.
365 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 35, paragraph 146.

been under-maintaining its assets (particularly its lines) for some time and its condition data does indicate a need for increased corrective maintenance in 2013–18. However, SKM, in its 2008 report to the AER, reached the same conclusion from ElectraNet's condition data and SKM expected overall opex spend to reduce as ElectraNet eliminates corrective maintenance backlogs.[366] EMCa considered the continued existence of these substation backlogs demonstrates ElectraNet has not prioritised them as being sufficiently high-risk to warrant expenditure to date.[367] SKM considered that corrective maintenance backlogs would be eliminated during the 2008–13 period, yet ElectraNet put forth these same propositions again five years later.[368]

EMCa considered ElectraNet's aim to entirely eliminate its backlog of defects, not only to be an unrealistic and unnecessary goal, but also a more aggressive strategy than it is currently applying (during 2008–13).[369]

EMCa observed that ElectraNet continued to present its asset management framework through stylised diagrams and theory rather than through factual and objective demonstration of achievement and realised measurable benefits.[370] EMCa found it difficult to accept ElectraNet's proposition (that is requires a further step change of the magnitude proposed) without such evidence.[371]

Further, EMCa found ElectraNet's defect information to be erroneous and contradictory.[372] It raised concerns that, in its review of ElectraNet's 2008–13 revenue proposal, SKM was advised that a complete cycle of substation assessment had already been completed at that time (five years ago). This contradicted information put forth by ElectraNet in its proposal for 2013-18 in which ElectraNet submitted these assessments would be complete by 2012-13.[373] EMCa observed that ElectraNet's forecast for zero-based additional substation backlog defects should not be added as a step change to base year extrapolated expenditure because an allowance for an urgent corrective backlog was funded in the current regulatory period as a one-off catch-up item. [374] SKM report to the AER noted:

> ElectraNet or their consultants have conducted condition assessments of all substations and a selection of lines. All substations were visited and inspected to prepare the condition reports. The transmission line assessments were generally paper-based reviews...these condition assessments have identified areas of defects which need further assessment or corrective maintenance. These works have been prioritised to determine the required timing. The process of prioritisation has been developed from condition assessment reports which cover all substation assets and most transmission lines..the high risk substation projects represent an expenditure of $8.4 million (2007-08) over the 2008–13 regulatory period..
>
> ..SKM is of the opinion that this large increase in expenditure includes a "catch-up" component for maintenance that would have been addressed earlier under a more sustainable asset management regime. Expenditure at this level should not be carried through into subsequent regulatory periods...certainly this cost category should experience significant reduction in the post 2013 regulatory period.[375]

SKM noted ElectraNet had undertaken detailed condition assessment reports for all its substation sites and that:

366 SKM, *Review of ElectraNet's revenue proposal 2008–13*, November 2007, page xiv.
367 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.35, paragraph 147.
368 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.36, paragraph 149.
369 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.36, paragraph 149.
370 EMCa *ElectraNet technical review - revised revenue proposal*, April 2013, p. 36, paragraph 148.
371 EMCa *ElectraNet technical review - revised revenue proposal*, April 2013, p. 36, paragraph 148.
372 EMCa *ElectraNet technical review - revised revenue proposal*, April 2013, p. 36, paragraph 149.
373 ElectraNet, *Revenue proposal*, p. 65.
374 ElectraNet notes in its revised proposal that the estimated value of this backlog incorporated in its original forecast was $2.5 million, ElectraNet, *Asset management plan*, May 2012, p.115. [Public version]
375 SKM, *Review of ElectraNet revenue proposal 2008–13*, p.112.

> Projects addressing medium asset risks have been included in the forecast but programmed over a ten year period....assets classed as high risk have been targeted for completion over 5 years during the next regulatory period.[376]

This comment reinforced EMCa's opinion that all the high risk defects and most of the medium risk defects identified in this pre 2008 condition assessment of all substation sites would most certainly have been corrected in the subsequent five years. EMCa stated 'it is beyond belief that the subsequent cycle of condition inspections would not find a significantly reduced number of high and medium risk defects'.[377]

Our forecast is a reasonable method to forecast prudent corrective maintenance. Actual maintenance expenditure in the base year on lines was $9.5 million (2010-11) compared with the allowance of $6.1 million (2010-11).[378] This variance was extrapolated in the base year escalation and should cover the backlog of works over time as the incoming rate of defects declines (as the cycle progresses). Any step change considered for 2013–18 comes on top of a step change in actual corrective maintenance spending in 2008–13. EMCa also noted our base year extrapolated approach reflects the level of work ElectraNet chose to undertake in 2008–13, work which was already based on the significant rounds of condition assessments.

Finally, ElectraNet noted that it has deferred two substation replacement projects through its adoption of the revised (lower) demand forecast, which it says will result in further pressure on substation corrective maintenance requirements.[379] We provided ElectraNet additional operational refurbishment step change in our final decision (above the draft decision) in recognition of the projects to be deferred due to the changed demand forecast. ElectraNet did not specify an amount for corrective maintenance, unlike for operational refurbishment, for a step change for corrective maintenance as a result of changed demand forecasts.

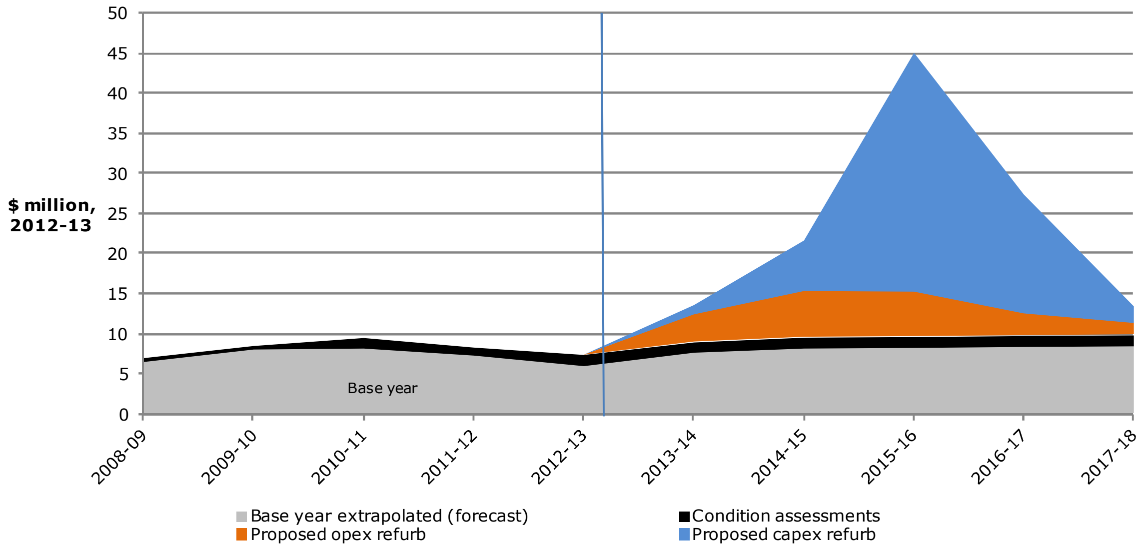
Operational refurbishment

We do not accept ElectraNet revised proposal of $66.8 million for operational refurbishment for 2013–18 meets the opex objectives. We substituted a base year extrapolated forecast of $48.9 million which includes a step change of $1.0 million. ElectraNet did not demonstrate any additional adjustment is required for its proposal to meet the NER criteria or NEL pricing principles. Our substitute forecast for operational refurbishment is a top down assessment and does not make any particular judgement on which projects or programs might practically differ from the program put forward by ElectraNet.

In our draft decision we noted ElectraNet had separated its operational refurbishment forecast over its opex and capex program and the total forecast for the 2013–18 regulatory control period was $119 million. This is nearly three and a half times the actual operational refurbishment expenditure in 2008–13 ($35.8 million) (Figure 3.8 and Figure 3.9).

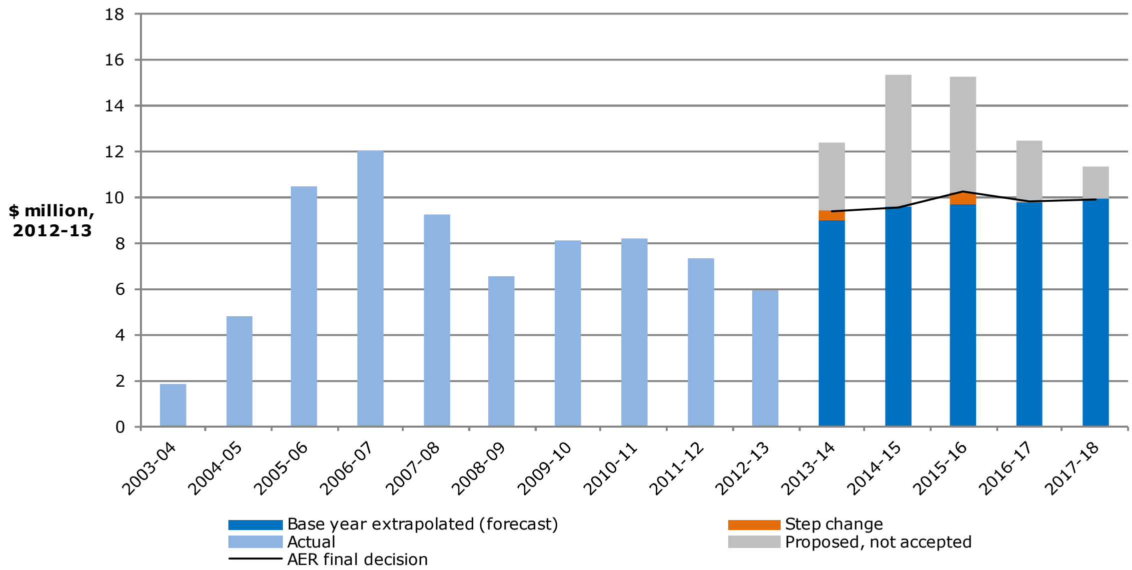
376 SKM, *Review of ElectraNet revenue proposal*, 2008–13, section 7.6.1 and 7.6.2.
377 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 34, paragraph 139.
378 ElectraNet, *Submission guideline template – historic opex* (ENET320).
379 ElectraNet, *Revised revenue proposal*, p.93.

Figure 3.8 ElectraNet's operational refurbishment: opex and capex ($ million, 2012-13)



Source: AER analysis.

Figure 3.9 ElectraNet's operational refurbishment: opex ($ million, 2012-13)



Source: AER analysis.
Note: Includes $1.0 million step change due to change in demand forecast

We reviewed ElectraNet's response to our draft decision. We are now satisfied that all the proposed projects, except the transmission lines condition assessment, appear to be consistent with the operational refurbishment categorisation. We do not accept ElectraNet's revised operational refurbishment forecast opex meets the NER opex criteria because ElectraNet did not demonstrate that its base-year expenditure was insufficient for it to maintain the reliability of the transmission system:

- ElectraNet's operational refurbishment proposal consists of 13 packaged programs of work. Operational refurbishment does not include high risk defects - these are undertaken in shorter timeframe as corrective maintenance. It includes some medium and low risk defects that ElectraNet determined will need to be addressed in 2013-18. Consistent with its total asset lifecycle methods, operational refurbishment projects justified by operational needs only (reliability and interruptions) should be tested by cost-benefit analysis against other options, such as early asset write off and replacement, corrective maintenance, or doing nothing.[380] Our primarily concern with ElectraNet's bottom up list of projects from which it based its forecast was that ElectraNet did not demonstrate its asset lifecycle optimisation (cost reduction) by engineering and economic options analysis in its operational refurbishment program.[381] In this respect it stated that it develops its asset refurbishment plans by considering all asset defect profiles (where possible, by plant group) so as to group and package work to maximise efficiency.[382] ElectraNet did not address the issue we raised in our draft decision, of the basis for determining its effective cut-off point, deferral options and trade off strategies for operational refurbishment decision making. It did not provide 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.[383] [384]

- Our substitute forecast, and EMCa's adjustment to ElectraNet's forecast, is a top down assessment and neither of these assessments makes any particular judgement on which projects or programs might practically differ from the program put forward by ElectraNet.

- ElectraNet has yet to financially commit to the specific projects or programs of work that it will undertake during 2013-18 but when it does so, we expect a prudent and efficient TNSP in these circumstances will undertake a more decision-focused business case. At that time it will likely find opportunities to prudently rationalise and to prudently defer projects and we note that ElectraNet spent less on opex refurbishment during 2008–13 than its allowance. EMCa's review found these projects appear to be reasonable to the extent that they address safety, environmental or bushfire risk. However, EMCa found ElectraNet is likely to have scope to prudently manage the activities, as occurred in 2008–13.[385]

- EMCa's top down review of the revised proposal did not change its view that around 50 per cent of the proposed increase from 2008–13 is a more reasonable estimate of the required increase in forecast expenditure. Our top down assessment arrived at substantially the same figure.

- Costs for transmission line condition assessments are included in the base year and extrapolated from the base year allowance.

- ElectraNet added $2.0 million in its revised proposal for asset defects at sites scheduled to be addressed through capex replacement works which were deferred by its revised demand forecast. We accepted only $1.0 million of these because some of these costs are likely to have scope for prudent management and packaging and should be captured by the base year extrapolated allowance.

Step change for change in demand forecast

In its revised proposal, ElectraNet adopted a lower demand forecast than its original proposal, which led it to defer substation rebuilds at Keith and Kincraig. It proposed these deferrals result in an increased operational refurbishment of $2.0 million. We accept that additional expenditure is required

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380 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p.39, paragraph 167.

381 AER, Draft decision: ElectraNet transmission determination, November 2012, p.158 - This comment was discussed in the corrective maintenance discussion but also applied more broadly to operational refurbishment, because the incoming defects are risk assessed and then prioritised and allocated to the packaged works stream (capex or opex refurbishment), corrective maintenance or monitoring. Whether a defect is allocated to the corrective maintenance or operational refurbishment works is governed by managerial discretion, assessment and policy.

382 ElectraNet, *Revised revenue proposal*, p.100.

383 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p.107.

384 ElectraNet, *Revised revenue proposal*, p. 95. ElectraNet notes that 'the remaining works are supported by high level cost benefit analysis based on quantified failure consequences and impacts'.

385 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p. 39, paragraph 166.

to enable the deferral of the replacement of the assets and maintain safety and performance but we found that a step change of $1.0 million was reasonable to meet the NER opex objectives because:[386]

- The revised project list includes $1.0 million for 'new' earthing remedial works that were not proposed in its draft decision (i.e. under the assumption of the higher demand forecast).
- The remaining works are packaged in other, pre existing, project categories. [387] For example, a component of the propsed costs for the Keith substation project is the 'replacement of battery charges' which is included in the 'Plant overhaul- battery chargers' program. ElectraNet describes this package of works as: approximately 15 per cent of all system battery chargers are faulty or at end-of-life (58 of 430 units).[388] We already addressed the forecast issues for this program, and have used a top down assessment. Our top down assessment does not make any particular judgement on which projects or programs might practically differ from the program put forward by ElectraNet. Whether the number of faulty batteries at end-of-life increases by a ferw units does not change the top down analysis of the 'package'.
- EMCa's advice that an increase of 50 percent of that sought is a reasonable top down estimate for the same reasons EMCa derived its top down adjustment. EMCa notes this increase of $1.0 million does not materially affect its 2012 advice.[389] It also observes that it has similarly disregarded as immaterial the reduction in routine opex that should in principle flow for ElectraNet's reduced augmentation and connection program.[390]

Transmission line condition assessments

One of the operational refurbishment projects is for condition inspection and testing activities to enable the first complete assessment of transmission line asset condition ($14.4 million).

ElectraNet states that if the transmission line inspection and testing was excluded then this would have the effect of disallowing funding for completing these specific activities, which would lead to an unacceptable increase in bushfire risk. It considered condition assessment was critical to help complete its understanding of the condition of transmission lines, to address safety and environmental issues, and to avoid quantified failure consequences and impacts.

Our top down forecast does not preclude or include any specific project or program of works and we are satisfied that the base year expenditure is a sufficient basis for ElectraNet to continue its current transmission line condition assessment program, without the need for a step-change because:

- The base year included condition assessment expenditure for transmission lines ($1.3 million), so our base year extrapolated forecast covers this type of activity ($8.6 million). Therefore, ElectraNet's revised proposal for transmission line condition assessments (as a zero based forecast) double counts the base year extrapolated costs if also applied as a step change.[391]

386 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p. 40, paragraph 174.

387 That is, the difference between the list of projects submitted for the initial revenue proposal (May 2012) and revised proposal (January 2013) was the addition of two substation projects SubS044 and SubS045 which were the earthing works. The other works identified by ElectraNet (refurbishment of isolators, transformer minor refurbishment, replacement of battery chargers, bund refurbishment) are considered in other refurbishment programs submitted in May 2012.

388 ElectraNet, *Revised revenue proposal*, table 7-3, p. 95. Similarly the other refurbishment costs are within other packaged works.

389 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p.40, paragraph 174.

390 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p.41, paragraph 175.

391 Some transmission line condition assessments were also capitalised during 2008–13, while the remediation works are proposed as opex in 2013–18 (see network optimisation).EMCa also noted that ElectraNet's capex model showed that a further $4.9 million is included for aerial surveys to identify line cleareances. It noted that this work was not much different in nature to other asset condition assessment work proposed in routine maintenance and operational refurbishment opex.[EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.17, paragraph 289].

- We are satisfied that the base year extrapolated approach provides ElectraNet sufficient allowance to prudently manage the scope and condition monitoring activities, as occurred in 2008–13. Condition assessments (opex) were conducted during 2008–13, costing $4.7 million[392] and ElectraNet proposed a further $14.4 million of line assessments for 2013–18.

The base year extrapolated forecast allows for $8.6 million which we consider is a reasonable amount to continue the remaining works because ElectraNet did not explain why the remaining line assessments are 3.3 times more costly than the first half of assessments. It spent $4.3 million on condition assessment expenditure in 2008–13, for 45 per cent of the assessments, yet proposed 3.3 times this amount to complete the remaining 55 per cent of assessments. Our top down forecast provides 1.6 times the 2008–13 actual costs to complete the remaining 55 per cent of assessment. This is, a 60 per cent real increase to address only 10 per cent more assessments. EMCa observed ElectraNet developed a very comprehensive approach to condition assessments and might have been able to produce higher economic value through sampling and a staged approach.[393]

We also note that ElectraNet provided contradictory information on the cost of condition assessments in its submission of its opex cost information template.[394] In the pro-forma template, it identified a total condition based maintenance cost of $0.22 million ($2008–09) in its user defined column 'condition maintenance' under its field maintenance category. In March 2013 it provided the condition assessment information costs only in response to our request.[395]

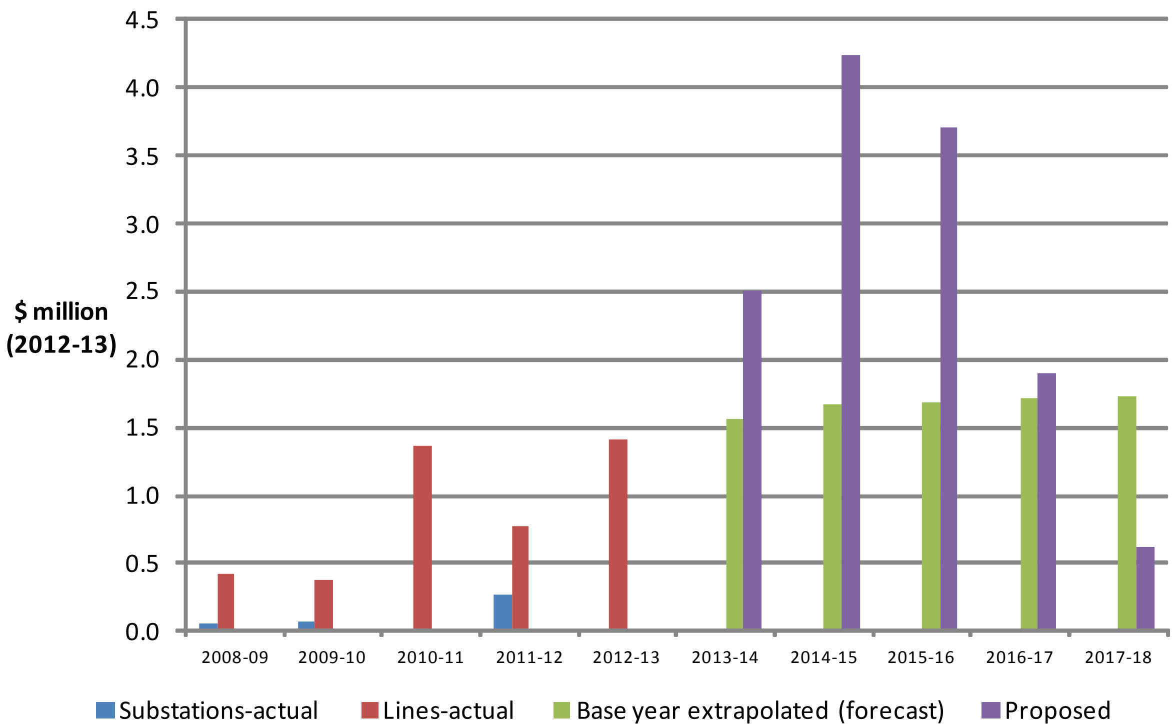
392 Includes $0.38 million for substation condition assessments, but no substation assessments were conducted in the base year (2012-11).

393 EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p.17, paragraph 66.

394 ElectraNet, ENET145, *AER Pro forma, Opex historic model*.

395 ElectraNet, ENET215, *Response to EMCa053 - Demand forecast reconciliation*, July 2012.

Figure 3.10 ElectraNet's condition assessments: actual and proposed costs ($ million, 2012–13)



Source: ElectraNet, *Email response to information request EMCa049 – Condition monitoring assessment, ENET214*; AER analysis.

Network optimisation

We are satisfied that ElectraNet's proposed expenditure of $4.9 million required to remedy line sags that are a material safety and compliance breach is required to maintaining the safety and security of the transmission system.[396] EMCa is satisfied the proposed works are a one-off correction to what was likely to have been non-compliant construction, though it is also possible for line sag to increase over time.[397]

EMCa regard the most suitable category as a one-off security/compliance project, categorised as capex, as the work is bringing the construction of these lines up to the standard at which they are supposed to operate.[398]

We support the inclusion of the expenditure in the forecast but have reclassified the expenditure as corrective maintenance (line remediation). ElectraNet's stated driver of the works is safety and security related, which does not fit well with a categorisation of 'Network optimisation'.[399] We consider this work is more appropriately classified as 'corrective maintenance' and have not accepted EMCa's reclassification of the works as capex.

EMCa considered the proposed line sag remediation work should be explicitly allowed for as a one-off expenditure item. ElectraNet acknowledged this type of work should also have ongoing expenditure,

396 ElectraNet *Revised revenue proposal*, p.102.
397 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p. 70, paragraph 283.
398 EMCa, *ElectraNet technical review - revised revenue proposal*, April 2013, p. 70, paragraph 284.
399 Even though the line works may improve network flow.

but thereafter should not be a material step change to the base level opex. We added this expenditure to the corrective maintenance forecast as a one-off step change and should be excluded from the future base year allowance (the forecast is $1.2 million ($2012-13) in 2016–17). We confirmed the work is not in our base-year extrapolated forecast under another opex category.

Opex efficiency factor

Our draft decision was to apply an opex efficiency factor adjustment of 2.5 per cent to the 2010–11 base year total controllable opex. We then trended this reduced base year amount to establish substitute forecasts for the next regulatory period (with limited step changes and other adjustments).

EMCa reviewed ElectraNet's reasons for not adopting our draft decision and considered its recommendation to apply the opex efficiency factor remains appropriate for the reasons it set out in its technical review.

The EUAA noted that Electranet is 'deeply concerned' about this and disagrees with ElectraNet's response to this issue, that such adjustments are contrary to the incentive regime that the AER is required to implement.[400] The EUAA submitted:

> the issue is what level of efficiency improvement should be expected as a matter of course, and what should be expected to result from above-average effort. The AER's 2.5 per cent adjustment is, we consider, too low. After inflation, expected at 2.5 per cent, Electranet's real opex will essentially remain constant. By comparison, across the Australian economy real productivity improvements of 1-2 per cent can be expected as a matter of course, with significantly greater improvements expected and achieved in various industries for long periods. In other words, just to keep up with the base level of productivity improvement across the economy, the AER's opex efficiency factor should be in the range of 3.5 per cent to 4.5 per cent, not 2.5 per cent.

It also submitted that:

> opex efficiency improvements greater than a reasonable expectation of the economy-wide improvement in productivity should be reflected in the AER's opex efficiency factor. The incentive scheme operated by the AER should only reward Electranet for improvements beyond a reasonable base level. Accordingly the EUAA propose that the AER increase its opex efficiency factor from 3.5 per cent to 4.5 per cent.[401]

While we recognise ElectraNet can be reasonably expected to achieve efficiencies against a base year extrapolated forecast, we will not apply the 1.5 per cent efficiency factor to the final decision. The AER's Better Regulation work program is considering our regulatory approaches across a number of issues. Given it is also developing guidelines on expenditure forecast assessments and incentives, we will not apply at this time an efficiency adjustment to ElectraNet's opex forecast.

3.4.4 Capex–opex trade off

The large increase in forecast field maintenance expenditure is driven by ElectraNet's new approach to asset management (its enhanced integrated condition management framework).

The principle of the capex–opex trade off is to recognise that consumers should be able to receive the benefits of their investment in ElectraNet's enhanced asset management framework in a reasonable timeframe.

In this section we first set out the concerns we have with ElectraNet's implementation of its enhanced integrated asset management regime (total asset life cycle (TALC) approach). We then discuss the method and basis for our capex–opex trade off adjustment.

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400 EUAA, *Submission on ElectraNet's revised proposal and AER's draft decision*, February 2013, p.18.
401 EUAA, *Submission on AER's draft decision and ElectraNet's revised proposal*, February 2013, p.18.

ElectraNet's implementation of total asset life cycle assessment approach

The TALC starts with a first round of condition assessments for all assets. After the initial condition assessments are complete, ongoing asset condition monitoring becomes incorporated in the routine maintenance plan. The initial information collected can be used to optimise asset management decision making through targeted maintenance programs, improved planning and packaging of works. The increased operating expenditure will be in the form of:

- a short term uplift for the collection of the initial condition assessments, IT infrastructure and some asset manager analysis/support
- a new stable state base level for the increased field maintenance effort (albeit declining over time as the new regime becomes more efficient and cyclical learning feeds back)
- a one-off backlog of defects that were otherwise unknown.

The purpose of this framework is to minimise the total asset lifecycle expenditure through optimised decision making, so the increased opex uplift should be offset by reduced capex (through deferral). Table 3.7 sets out this process.

Table 3.7 Expenditure implications from moving to the TALC approach

Type	Category	Change under new regime
Opex	Field maintenance (all categories)	Field maintenance operators have embarked on a program to comprehensively assess the condition of all field assets. All substation assessments and 45 percent of transmission line assessments are complete.402 This change in method has led to a (short term) increase to the rate of incoming defects and given rise to a back log of previously unknown defects. ElectraNet allocates the defects to corrective maintenance or capex operational refurbishment or opex operational refurbishment at its discretion.
Opex	Field maintenance–-routine	The frequency of the routine maintenance activities increases. Ongoing condition assessments (beyond the first round of assessments) are incorporated into the scheduled routine maintenance program. In recognition of this arrangement and of ElectraNet's commitment to improving its asset condition we accepted its routine maintenance forecast as a step change to its revealed cost forecast.
Opex	Field maintenance–corrective	The incoming rate of defects temporarily increased because the data collection method has changed, leading to an apparent backlog. The ongoing 'base level' should tend to a lower stable state because the increased asset intelligence should result in less ad hoc, unplanned corrective action.
Opex	Field maintenance–-refurbishment	Improved asset condition intelligence should lead to optimised decision making for packaged works. ElectraNet included the remaining condition assessment activities (for transmission lines).
Capex	Refurbishment	ElectraNet added a new category of expenditure to its capex forecast.
Capex	Replacement	The aim of this program is to increase the life of assets and decrease total asset lifecycle costs. Ultimately, the increased opex should lead to deferred capex.

Source: AER analysis.

Our main concern with the implementation of ElectraNet's TALC approach was whether the framework has led it to develop efficient and prudent expenditure forecasts. We do not accept ElectraNet's proposed forecasts are efficient or prudent, because:

402 ElectraNet, *Response to information request EMCa 046, Asset condition and corrective maintenance, ENET211,* p. 6.

- ElectraNet's decision to commit resources to its new asset management approach is entirely endogenous. That is, the form, size and timing of its 'investment' is decided entirely by its management but not by an external driver. ElectraNet did not demonstrate the benefits that customers can expect to achieve through ElectraNet's upfront investment in the new system. It did not demonstrate that its forecasts, based on these investment decisions, are consistent with the NEL objective and NER opex criteria.

- EMCa considered condition based maintenance regimes are generally good industry practice, and ElectraNet's asset management framework design and structure is consistent with such regimes. However, it raised concerns that ElectraNet has not implemented the TALC asset management strategy in an efficient or cost effective manner. EMCa also stated ElectraNet had not accounted for the benefits from the investment in its TALC approach.

- ElectraNet claimed the incremental cost of implementing its TALC maintenance regime was $30.1 million ($2011-12), rather than the $46.3 million estimated by EMCa.[403] EMCa noted ElectraNet produced a cost breakdown of the incremental costs of implementing its enhanced condition based maintenance regime only in response to the AER's draft decision. ElectraNet set out its cost estimate and compared it with EMCa's estimate. ElectraNet did not describe its method for calculating its estimate, nor its assumptions and why its estimate was lower than EMCa's (other than to claim EMCa's estimate reflected the entire cost of its condition based maintenance regime and not the incremental cost of the enhanced regime). We accept EMCa's final advice on this matter, which is that the incremental cost of the enhanced condition based maintenance regime is $46.3 million[404] but we estimate the all up cost of $39.5 million with consideration of the components of our final decision.

- ElectraNet did not provide a business case that considered all the costs ahead of the program's implementation to inform its strategic decision. A business case would have identified the benefits and costs, and its absence meant we could not assess the benefits that consumers can expect from their upfront investment. Given the TALC regime is a significant investment and major strategic initiative, EMCa considered the lack of a business case indicates a weakness in ElectraNet's internal governance processes.[405] While condition based maintenance may represent good industry practice, EMCa found it reasonable to expect ElectraNet would evaluate and document its decision to move to this form of maintenance before committing significant expenditure to it. In particular, it would be reasonable to expect ElectraNet to demonstrate the approach is applicable for ElectraNet's business and economically justified.[406]

- EMCa also found ElectraNet could have imposed stronger project management disciplines before committing so much investment in time, money and strategic direction to the extensive maintenance model. An alternative approach to implementing full condition based maintenance, such as through a staged or sampling approach, might have produced higher economic value. The absence of a business case means this potential value is forgone.[407]

- ElectraNet did not support its forecast with a cost–risk analysis to show the optimal timing for asset replacement or life extension decisions. ElectraNet did not provide basic form of engineering economic options analysis, even though we specifically requested such material in our draft decision.

[403] ElectraNet, *Revised revenue proposal*, table 5-1, p. 35; EMCA, *Technical review*, November 2012, p. D-5.
[404] EMCa, *ElectraNet technical review - Revised revenue proposal*, April 2013, p. 24, paragraph 91.
[405] EMCA, *Technical review*, 30 November 2012, pp. 19, 119-20.
[406] EMCA, *Technical review*, 30 November 2012, pp. 19, 119-20.
[407] EMCA, *Technical review*, 30 November 2012, pp 119-120.

- EMCa's view was that ElectraNet's mechanisms for asset strategy optimisation are not yet mature and may not be producing fully optimised outputs. We accept this advice, and section 3.4.3 sets out the detailed reasoning.

- ElectraNet's asset management plan describes its asset risk prioritisation process. This process uses outputs from its risk prioritisation tool to provide a measure of its unacceptable risk exposure relative to the resource constraint.[408] ElectraNet qualitatively demonstrated the sensitivity of the risk to resource constraint.[409]But it did not demonstrate how management uses the information collected on asset condition to optimise the timing for asset replacement compared with life extension. ElectraNet's risk prioritisation process has two output profiles: the prioritised planning profile based on the risk profile and the prioritised work schedule based on the financial profile. These profiles allocate defects/works to corrective maintenance or refurbishment (opex or capex), but ElectraNet did not present evidence of economic analysis aimed at determining the appropriate cut-off points and actions. [410] This is important because the risk prioritisation tool interacts with the financial plan (input) yet ElectraNet did not show how its financial plan (for 2013–18) interacts with its prioritised work schedule for 2013–18. When ElectraNet filed its proposal in May 2012 the financial plan could not have included an allowance for 2013–18, and we expect a prudent and efficient TNSP would perform a sensitivity analysis to show the cost–risk trade off. The system that ElectraNet has developed is sophisticated and comprehensive, and should have this capacity, but ElectraNet did not provide this information to us or EMCa. [411]

Capex–opex trade off adjustment

Our final decision is to apply a capex–opex trade off adjustment of $5.5 million ($2012–13) to ElectraNet's replacement capex forecast. In coming to this decision, we considered ElectraNet's response to our draft decision and EMCa's technical advice. We revised the amount of the capex–opex trade off adjustment from $50 million ($2012–13) in our draft decision upon consideration of the issues set out in this section.

As discussed in attachment 3 of our draft decision, we observed that ElectraNet's proposal contained increases in opex and replacement/refurbishment capex largely driven by ElectraNet's improved asset management framework.[412] The key issue for our assessment is whether the consumer's investments in ElectraNet's improved asset management framework, which drives significant forecast expenditure increases, resulted in efficient expenditure forecasts consistent with a prudent operator.[413]

Our draft decision considered ElectraNet's integrated asset management framework and design is consistent with good industry practice and that the investment in the framework is capable of delivering material benefits to ElectraNet and its customers.[414] 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. However, ElectraNet has not sufficiently factored the expected benefits of the framework into its revised regulatory proposal. As a result, the revised proposal is overstated and does not satisfy the opex and capex criteria.[415] In this context, although the full economic benefits have not been demonstrated, we approved scope changes to the field maintenance opex category. This results in an opex allowance increase above the revealed cost forecast.

408 ElectraNet, *Asset management plan 2013-18*, ENET036, pp.109-10 [Public version].
409 ElectraNet, *Asset management plan 2013-18*, ENET036, pp.109-10 [Public version].
410 EMCA, *information request, EMCA14 - Asset management framework business case*, 25 July 2012.
411 ElectraNet, *Asset management plan 2013-18*, ENET036, pp.109-10 [Public version].
412 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 99-109.
413 NER, clauses 6A.6.6(c) and 6A.6.7(c).
414 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 100-101.
415 NER, clauses 6A.6.6(c) and 6A.6.7(c).

At the same time, we expect 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, we consider 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. Thus, consistent with our draft decision, we have made a capex–opex trade off adjustment to account for the benefits consumers should receive from their investment in ElectraNet's integrated asset management framework. This adjustment is based on the incremental costs of the deployment of ElectraNet's enhanced condition–based maintenance regime (the regime) and taking into account the quantifiable benefits.

In its submission on ElectraNet's revised proposal and the AER's draft decision, EUAA supported our approach to the substantial increase in opex to account for expenditure that Electranet has proposed, to improve its field maintenance / condition assessment systems. It was concerned that Electranet has not taken account of the savings that such higher expenditure will deliver, but rather that ElectraNet has alluded to savings arising, possibly, in future regulatory periods, which EUAA suggest is unrealistic[416]:

> If our members sought approval for such large increases in their operating costs, they can be expected to have to justify it by demonstrating savings that exceed the cost of the investment. Electranet has not done this. Noting again, the evidence of comparatively high operating costs and sustained increases to-date, we can not support further substantial increases in the absence of off-setting savings of at least the level of the increase attributable to the investment in field maintenance / condition assessment systems.

In its submission on the AER's draft decision and ElectraNet's revised proposal, the ECCSA agrees that an increase in routine maintenance that is associated with the new approach to asset management could well provide a net benefit to consumers yet there are no obvious savings identified to offset the large increases that have been granted:

> The AER needs to provide definitive information that increasing the costs of the new asset management process is element by such a large proportion is coupled with savings in other areas to demonstrate that increasing the allowance is efficient and provides a net benefit. In fact the AER has allowed increases in other elements of the opex which reflect the normal growth that might be expected rather than any definitive outcomes. The outcomes from an increased cost in routine maintenance should result in lower corrective maintenance, operational and capital refurbishment and an increase in service standards. What is seen from the AER draft decision is that replacement and refurbishment capex has increased, corrective and refurbishment opex have increased and service standard targets are virtually unchanged or lower compared to ElectraNet performance [during 2008–13]. There is no obvious benefit that consumers see from the increased opex allowances. [417]

ElectraNet's revised proposal disputed the application of the capex–opex trade off for the following reasons:[418]

- ElectraNet's forecast already accounts for capex deferrals
- our draft decision overstated the incremental costs of the regime
- the capex–opex trade off adjustment is an ex–post adjustment.

ElectraNet considered its forecast already accounts for $275 million benefits of capex deferrals.[419] We consider that the capital to be deferred from 2007 to 2019 is likely to be in the order of $11.2 million

[416] EUAA, *Submission on ElectraNet's revised revenue proposal and AER draft decision*, February 2013, p.18
[417] ECCSA, *Submission on ElectraNet revised proposal and AER draft decision*, February 2013, pp.23-24.
[418] ElectraNet, *Revised revenue proposal*, p. 45.

($2012-13) , but that the savings of the capital deferred will be much less than this.[420] This deferral of expenditure is not absolute savings and the net present value of savings is represented by the cost of capital applied to the deferred expenditure (the amount and number of years of deferral.[421] EMCa concluded that, given the significant possibility that the deferral was reasonably likely to be due to reductions in demand, it was unconvinced by ElectraNet's argument that the implementation of condition-based maintenance led to the deferral of this project.[422] While we accept EMCa was been unable to find direct evidence to support ElectraNet's contention, we were did not find evidence that the Happy Valley substation deferral was driven by other factors either. Therefore, we accept that ElectraNet has accounted for at most $11.2 million of capex deferred from its expenditure forecast and we have revised our calculations accordingly.

ElectraNet further considered the incremental costs of the regime to be $30.1 million ($2011–12)[423] but did not provide a justification for its cost estimate, method or assumptions.[424] However, we note that ElectraNet provided this estimate only in response to our draft decision[425] and this estimate appears to contradict other material it submitted.[426] EMCa found the incremental costs of the program to be $46.3 million ($2012-13) which includes the line condition assessment expenditure proposed by ElectraNet. Our estimate of the incremental costs of the program is $40.1 million, which includes the line condition assessment in the base-step-trend forecast. Our estimate, method and assumptions are shown in Table 3.9.

Finally, ElectraNet stated that we are not in a position to apply an ex–post adjustment for prior period expenditure.[427] While we acknowledge ElectraNet's statement, we consider the capex–opex trade off is not an ex–post adjustment. Rather we consider the principle of this adjustment is to recognise that the benefits should at least match the investment costs in a reasonable timeframe and, that the timeframe is likely to be longer than a five year regulatory control period.

Given the absence of any cost–benefit analysis from ElectraNet and that it did not demonstrate that the benefits that consumers can expect exceed the incremental costs in a reasonable timeframe, we applied an adjustment of $5.5 million as set out in Table 3.8. The elements of this calculation are discussed in the rest of this section.

While this adjustment assumes benefits should exceed the costs in a 10 year period, it does not account for the present value of the capital deferrals. We recognise that the benefits to consumers' for their investment in ElectraNet's new systems may lag the upfront costs, but we consider the benefits should be evident in a reasonable timeframe. We accept EMCa's advice that an investment in such a

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419 ElectraNet, *Revised revenue proposal*, p. 4\93. We note that the text refers to $275 million while the supporting table (Table 5–3) presents $273 million.

420 ElectraNet, *2007 Asset Management Plan, Appendix 15*, page 156: project number 10616 Happy Valley substation. The estimated project cost was $9.8 million ($2007-08) which converts to $11.2 million ($2012-13).

421 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 19–20, paragraph 74.

422 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 19–20, paragraph 74.

423 ElectraNet, *Revised revenue proposal*, p. 41, Table 5–1.

424 ElectraNet also claimed EMCa's estimate reflects the entire cost of the regime, not the incremental cost of the enhanced regime. EMCa disputed this and maintained that its estimate is based on the incremental cost of the regime. EMCa made some amendments to its estimate (April 2013) and revised its estimate to $46.3 million. See: EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 24, Table 8.

425 ElectraNet responded that the integrated asset management framework was developed from a 2008 asset data and information management plan and that it approved the implementation via annual business unit plans and budgets. Thus our draft decision set out that it would be a matter of good governance for ElectraNet to undertake a mid–implementation review to set objective and measurable benefit target. ElectraNet provided no evidence of its commitment to this total strategy on the basis of a cost–benefit analysis, either before or after our draft decision was published.

426 ElectraNet, Cost information template - opex. ElectraNet presented that the cost of condition monitoring was about $200,000. This value was submitted in ElectraNet's cost information template under the user defined column of the condition assessments component of field maintenance.

427 These estimates are based on the cumulative present value of a marginal increase to opex allowance of (a) $5 million per annum for 10 year or (b) $3 million per annum for 10 years, commencing in 2010–11 less the cumulative present value of the cashflow at the end of 2012–13 respectively. That is, the ex-post expenditure has been removed.

change in work practices should achieve a payback at least within a five to ten year period is a reasonable timeframe.[428] Given ElectraNet's incremental expenditure increase on the enhanced asset management regime began during 2008–13, we therefore consider that a reasonable period in which costs should match benefits is by the end of 2013–18.

Table 3.8 Costs and benefits for the capex–opex trade off calculation ($ million, 2012–13)

Adjustment	Increment	Total
Incremental cost of enhanced maintenance regime (TALC)[a]		46.3
Lines condition assessment forecast 2013–18[a]	–14.4	31.9
Incremental expenditure during 2008–13 (ex–post expenditure)	–15.2	16.7
Happy Valley substation deferral [b]	–11.2	5.5
Shortfall		5.5

(a) The total incremental cost assumes a routine maintenance increment of $3.0 million per annum commencing 2010–11, incremental support costs of $0.2 million per annum during 2008–13 and $0.3 million per annum during 2013–18, the 2008–13 lines and substations operational refurbishment costs identified by ElectraNet. It assumes the lines assessments of $14.4 million as proposed by ElectraNet. See: ElectraNet, *Email response to information request EMCa 049, Condition monitoring assessment*, July 2012.

(b) This deferral assumes the benefit of the full capital cost, not the value of the deferral which is: capital x WACC x years deferred.

Incremental costs of enhanced maintenance regime

Table 3.9 shows our estimate of the incremental cost of the enhanced asset maintenance regime.

428 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 26, paragraph 98.

Table 3.9 Incremental cost of enhanced asset maintenance regime ($ million, 2012–13)

	Routine	Refurb. subs	Refurb. lines	Support	Capex IT	Total	Lines condition proposed	Lines condition base year
2008-09		0.05	0.42	0.2		0.67		
2009-10		0.07	0.38	0.2		0.64		
2010-11	3.00	0.00	1.37	0.2		4.57		
2011-12	3.00	0.26	0.77	0.2	0.50	4.73		
2012-13	3.00		1.41	0.2		4.61		
2008–13	**9.00**	**0.38**	**4.34**	**1.00**	**0.50**	**15.22**		
2013-14	3.00			0.30		3.30	2.7	1.57
2014-15	3.00			0.30		3.30	4.6	1.67
2015-16	3.00			0.30		3.30	4.1	1.69
2016-17	3.00			0.30		3.30	2.2	1.71
2017-18	3.00			0.30		3.30	0.8	1.73
2013–18	**15.00**			**1.50**		**16.50**	**14.4**	**8.37**
TOTAL	**24.00**					**31.72**		
EMCa Total							**46.3**	
AER Total								**40.1**

Source: EMCa analysis based on ElectraNet, *Email response to information request EMCa049 - Condition monitoring assessment*, ENET214.

Note: The estimate for routine maintenance during 2013–18 of $15.0 million ($2012–13) differs from the AER's imputed step change of $9.0 million ($2012–13) because we accepted ElectraNet's routine maintenance proposal in full and the step change was imputed using an already increased routine maintenance expenditure in the 2010-11 base year.

ElectraNet contended the lines condition assessment work, proposed expenditure for the 2013–18 regulatory control period of $14.4 million ($2012-13), cannot provide incremental benefits in the same period since no lines replacement capex is proposed in this period. We recognise that the benefits arising from expenditure in one period may not be evident until future regulatory periods. For this reason we removed the line condition assessments from our analysis because we understand the benefits arising from this work will be evident in 2018–23.

While acknowledging that benefits and costs may not align to a regulatory period, ElectraNet also submit that we cannot adjust for expenditure from previous regulatory periods because it considers this an ex-post expenditure adjustment. This presents a logical inconsistency for us because the benefits will lag the upfront costs (and in many cases by more than five years) yet our overarching principle is set out in the NEO as considering the long term interests of consumers. ElectraNet also acknowledge that it took any economic benefits into account in its forecast. We excluded the $15.2 million from our analysis for 2008–13 expenditure but maintain the principle that the reason for the adjustment is for the shortfall in benefits that consumers should receive in a reasonable period.

Benefits to consumers

ElectraNet acknowledged that economic benefits should be evident in 2013–18, but that it had accounted for these benefits already in its capex forecast:[429]

> [ElectraNet's] expenditure forecasts have been developed based on the best asset condition information available from its enhanced condition-based maintenance regime and so any economic benefits have already been taken into account in the forecast period through deferred substation and line replacement investment timing.

ElectraNet submitted it has deferred $275 million of planned substation costs from its 2007 asset management plan and that these benefits are already captured in the expenditure forecasts.[430] EMCa reviewed these purported capex deferrals and found ElectraNet's claim to be without substance, and we accept EMCa's reasons.[431] EMCa showed that the capital to be deferred from 2007 to 2019 is likely to be at most $11.2 million ($2012-13), but that the value of the deferral will be much less than this.[432] That is, we consider that ElectraNet had accounted for at most $11.2 million of capex deferrals in its expenditure forecast.

ElectraNet initially submitted that its approach has allowed the delaying of replacements in excess of $3.5 billion over what would otherwise be required over two regulatory control periods.[433] For our draft decision, EMCa considered this claimed deferral benefit appeared to be implausible relative to its actual replacement capex in the 2008–13 regulatory control period and its revised proposal replacement capex.[434] ElectraNet's revised revenue proposal submitted that it has deferred $275 million of planned substation costs from its 2007 asset management plan and that these benefits are already captured in the expenditure forecasts.[435] This expenditure comes from a total of seven projects identified by ElectraNet.

EMCa reviewed the seven projects with reference to ElectraNet's 2007 asset management plan and the subsequent annual asset management plans. In EMCa's view a project would need to satisfy a number of conditions to justify ElectraNet's claim of savings:[436]

- be included in the 2007 asset management plan
- be a substation replacement project
- have been scheduled in the 2007 asset management plan for construction prior to 2019; and
- be deferred beyond the 2013–2018 regulatory control period in the revised revenue proposal.

EMCa was unable to find evidence in ElectraNet's 2007 asset management plan that supported ElectraNet's claims that these major substation replacement capital projects were planned. If these projects had been planned they would have been included in ElectraNet's capital projects plan[437] which lists all the planned capital projects to 2025. EMCa found that only one replacement capital project in the capital projects plan was attributable to the listed substations (Happy Valley 275kV Secondary Systems replacement, $11.2 million ($2012-13)).[438] ElectraNet's other six identified

[429] ElectraNet, Revised revenue proposal, 16 January 2013, p.39
[430] ElectraNet, *Revised revenue proposal*, p. 43.
[431] EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, pp. 18-21, paragraphs 72-79.
[432] EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 19–20, paragraph 74.
[433] ElectraNet response to matters raised at 3 October 2012 meeting, *Capex replacement and maintenance decision framework*, ENET 271, October 2012, p. 9.
[434] EMCa, *ElectraNet technical review*, Appendix D – Addendum report, October 2012, p. D-6.
[435] ElectraNet, *Revised revenue proposal*, p. 43.
[436] EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 18, paragraph 71.
[437] ElectraNet, *Asset management plan*, 30 May 2007, appendix 15.
[438] EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 19, paragraph 74.

substation deferrals did not meet the criteria. We accept EMCa's reasons and analysis of costs and benefits of the enhanced asset management regime set out in its April 2013 report.[439] EMCa also raised concerns that it is difficult to ascribe causality to deferrals and it is also difficult to determine whether any deferrals have occurred due to the implementation of the program, prudency reviews, lower growth expectations, or other factors.[440] EMCa could not be certain whether these deferrals were due to reductions in condition monitoring or changes in demand forecasts.[441]

3.5 AER decision

Decision 3.1: Table 3.1 and table 3.2 present our final decision on operating expenditure for the 2013–18 regulatory control period.

439 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 17–21, paragraphs 67–79.

440 EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, pp. 17–19, paragraphs 67-73.

441 The forecast for 2012 demand in the 2007 annual planning report was 4180MW while in the 2012 annual planning report the forecast for 2020 demand was 4170MW. This difference suggest the deferrals might be due to reductions in demand forecasts and we note ElectraNet's revised revenue proposal includes reductions in replacement capex as a result of lowering demand forecasts.

4 Cost of capital

As part of making a determination on the annual building block revenue requirement for a TNSP, we are required to make a decision on the return on capital building block.[442] 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 RAB.

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.[443]

4.1 Final decision

We accept ElectraNet’s proposed method for estimating the weighted average cost of capital (WACC). Consistent with this method, we have updated ElectraNet’s revised proposal WACC to reflect the agreed averaging period.[444] This results in a WACC of 7.50 per cent.

Our final decision on WACC only differs from ElectraNet's revised revenue proposal due to the use of different averaging periods for estimating the risk free rate and the debt risk premium (DRP). Specifically, ElectraNet's revised WACC was based on market data from September–October 2012. Our final decision, however, is based on market data from February–March 2013. We agreed to the averaging period proposed by ElectraNet. We consider a 7.50 per cent rate of return provides ElectraNet with a reasonable opportunity to recover at least the efficient costs of capital financing. Consequently, we expect 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.

Table 4.1 sets out the individual WACC parameters and subsequent rate of return which we have determined.

442 NER, clause 6A.5.4(a)(2).
443 NER, clause 6A.6.2(b).
444 ElectraNet's approved averaging period is the 20 days (on which indicative mid rates are published by the Reserve Bank of Australia) commencing on 18 February 2013.

Table 4.1 AER's final decision on WACC parameters

Parameter	AER draft decision	ElectraNet revised proposal	AER final decision
Nominal risk free rate	3.51%	3.51%	3.51%
Equity beta	0.8	0.8	0.8
Market risk premium	6.50%	6.50%	6.50%
Debt risk premium	3.18%	3.18%	3.18%
Gearing level	60%	60%	60%
Inflation forecast	2.5%	2.5%	2.5%
Nominal post tax cost of equity	8.71%	8.71%	8.71%
Nominal pre tax cost of debt	6.69%	6.69%	6.69%
Nominal vanilla WACC	7.50%	7.50%	7.50%

Source: AER analysis and ElectraNet, *Revised revenue proposal*, p. 126.
Note: Our draft decision, and ElectraNet's revised proposal parameters have been updated to reflect the final averaging period, based on the respective methodologies. The parameters published in our draft decision and revised proposal were calculated on an indicative averaging period from September–October 2012. Our final decision reflects data from February–March 2013.

4.2 Assessment approach

We did not change our assessment approach for individual parameters from our draft decision. Section 6.3 of attachment 6 of our draft decision details that approach.[445]

4.3 Reasons for final decision

ElectraNet's proposed method for determining the WACC adopted the values 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).[446] Under the NER, in estimating the rate of return we must use the values, and credit rating determined in the WACC review to estimate the rate of return.[447] We therefore accept ElectraNet's proposed values for these parameters.

In establishing the WACC, we also accept ElectraNet's proposed method for determining the DRP, the nominal risk free rate and inflation forecasts. Consistent with this method, we have updated ElectraNet's revised proposal WACC to reflect the agreed averaging period. Our reasons for accepting these methods are consistent with those adopted in our draft decision. Accordingly, this material is not reprinted here. See section 6.4 of attachment 6 of our draft decision for this detail.[448]

In forming this final decision, we also considered submissions from the Energy Consumers Coalition of South Australia (ECCSA) and the Energy Users Association of Australia (EUAA). While the EUAA restated its concerns with the continued use of the Bloomberg fair value curve to estimate the DRP, it acknowledged our intent to consider this issue in the development of the rate of return guidelines.[449]

445 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 166-168.
446 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.
447 NER, cl. 6A.6.2(h)
448 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 168-171.
449 EUAA, Submission to the AER on ElectraNet Revenue Draft Determination 2013/14 to 2017/18, 19 February 2013, p. 24.

The ECCSA's submission also focused on the DRP, including our response to ECCSA's submission on ElectraNet's initial revenue proposal.

In response to ElectraNet's initial revenue proposal, the ECCSA provided analysis based on annual report data. In our draft decision, we stated that it is inappropriate to calculate the DRP for an entire portfolio with reference to only the 10 year risk free rate.[450] To estimate the DRP, we consider that the risk free rate used should match the term of the debt being considered. For example, to determine the DRP for a bond with a remaining term of five years, the five year risk free rate should be used. The DRP of a portfolio of a debt, therefore, should comprise of the average DRP calculated for each separate debt issuance. The ECCSA approach, however, does not match the term of debt with the term of the risk free rate. To the extent the average term of the portfolio differs from the term of the risk free rate, this term mismatch may under estimate or over estimate the DRP.

The ECCSA also raised concerns regarding the confidential nature of the averaging period proposed by ElectraNet (and used to estimate the risk free rate and the DRP). In particular, the ECCSA stated that the averaging period proposed by ElectraNet should be disclosed to allow stakeholders to assess its reasonableness. The NER allow us to accept ElectraNet's request to keep its averaging period confidential but only until the agreed period expires.[451]

In agreeing to accept ElectraNet's request, we had regard to the fact that we require the proposed averaging period to be agreed to in advance of the period itself. We consider this minimises the ability for networks to select an averaging period that will result in a systematic bias. We also considered that, should ElectraNet seek to refinance, or engage in hedging transactions during the averaging period, disclosing this period to market participants may lead to higher financing costs.[452] This increase in costs is unlikely to be in the long–term interests of consumers.

4.4 AER Decision

Decision 4.1: The AER has determined a WACC of 7.50 per cent for ElectraNet, as set out in Table 4.1.

450 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 170.

451 NER, 6A.6.2(c)(iii)

452 For example, transactions entered into during the averaging period may better hedge the interest rate risk faced by ElectraNet for the subsequent access arrangement period. Accordingly, market practitioners could charge—and ElectraNet may be willing to pay—a premium for transactions during this period. This premium can be avoided by maintaining confidentiality of the period until it has elapsed.

5 Regulatory asset base

We are required to determine ElectraNet's regulatory asset base (RAB) for the 2013–18 regulatory control period.[453] We set the RAB as the foundation for determining ElectraNet's revenue requirement, and we use the opening RAB for each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block allowances. This attachment presents our final decision on ElectraNet's opening RAB as at 1 July 2013 and includes an assessment of an issue relating to movements in capitalised provisions raised in ElectraNet's revised proposal. It also presents our forecast of the RAB for the 2013–18 regulatory control period.

5.1 Final decision

We determine ElectraNet's opening RAB value as at 1 July 2013 to be $2069.5 million ($nominal). This value is $17.8 million (0.9 per cent) lower than ElectraNet's value of $2087.3 million in its revised proposal because we made the following changes to the roll forward of the RAB:

- Consistent with our draft decision, we adjusted the actual capital expenditure (capex) values rolled into the RAB to reverse the movements in capitalised provisions. We consider capitalised provisions should not be included in the RAB until ElectraNet has paid out (incurred) the expenses to which the provisions relate.
- We updated the inflation input for 2012–13 using the actual March 2013 consumer price index (CPI) published by the Australian Bureau of Statistics (ABS).

We forecast ElectraNet's RAB to be $2620.3 million by 30 June 2018. This forecast represents a reduction of $70.6 million (2.6 per cent) to ElectraNet's revised proposal. The main reasons for this reduction are our adjustments to:

- forecast capex (attachment 2)
- the opening RAB as at 1 July 2013 (section 5.4.1).

Table 5.1 and Table 5.2 set out our final decisions on the roll forward of ElectraNet's RAB during the 2008–13 regulatory control period and the forecast RAB for the 2013–18 regulatory control period respectively.

[453] NER, clause 6A.6.1.

Table 5.1 AER's final decision on ElectraNet's RAB roll forward for the 2008–13 regulatory control period ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13[a]
Opening RAB	1311.8	1390.6	1493.6	1723.9	1866.4
Capital expenditure[b]	101.5	122.8	243.9	181.9	236.5
CPI indexation on opening RAB	32.4	40.2	49.8	27.3	46.7
Straight-line depreciation[c]	–55.0	–60.0	–63.3	–66.7	–73.3
Closing RAB as at 30 June	1390.6	1493.6	1723.9	1866.4	2076.3
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					–2.4
Opening RAB as at 1 July 2013					2069.5

Source: AER analysis.
(a) Based on estimated capex. An update for actual capex will be made at the next reset.
(b) As incurred, net of disposals, and adjusted for actual CPI and weighted average cost of capital (WACC).
(c) Adjusted for actual CPI. Based on as-commissioned capex.

Table 5.2 AER's final decision on ElectraNet's forecast RAB for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18
Opening RAB	2069.5	2259.8	2376.7	2503.9	2596.1
Capital expenditure[a]	217.4	149.7	172.5	146.2	78.3
Inflation indexation on opening RAB	51.7	56.5	59.4	62.6	64.9
Straight-line depreciation[b]	–78.9	–89.3	–104.8	–116.5	–119.0
Closing RAB	2259.8	2376.7	2503.9	2596.1	2620.3

Source: AER analysis.
(a) As incurred forecast, and net of disposals. In accordance with the timing assumptions of the post tax revenue model (PTRM), the forecast capex includes a half-WACC allowance to compensate for the six months before capex is added to the RAB for revenue modelling purposes.
(b) Based on forecast of as-commissioned capex.

5.2 ElectraNet's revised proposal

ElectraNet incorporated all aspects of our draft decision on the opening RAB as at 1 July 2013, except our adjustment to movements in provisions. ElectraNet updated its capex inputs for 2011–12 and 2012–13. It also updated the inflation forecast for 2012–13 in the revised roll forward model (RFM). It noted that the AER would update the RAB roll forward with actual March 2013 CPI for the final decision.[454] Table 5.3 and Table 5.4 summarise ElectraNet's revised RAB roll forward and RAB forecast respectively.

Table 5.3 ElectraNet's revised RAB roll forward for the 2008–13 regulatory control period ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13
Opening RAB	1311.8	1391.6	1495.5	1725.7	1868.6
Capital expenditure[a]	102.4	123.8	243.7	182.4	238.4
CPI indexation on opening RAB	32.4	40.2	49.8	27.3	60.7[c]
Straight-line depreciation[b]	–55.0	–60.1	–63.4	–66.8	–73.6
Closing RAB	1391.6	1495.5	1725.7	1868.6	2094.1
Difference between forecast and actual capex (2007–08)					–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 assets under construction					–2.5
Closing RAB as at 30 June 2013					2087.3

Source: ElectraNet, *Revised RFM*, January 2013.
(a) As incurred, net of disposals, and adjusted for actual CPI and WACC.
(b) Adjusted for actual CPI. Based on as-commissioned capex.
(c) Based on forecast CPI.

Table 5.4 ElectraNet's revised RAB forecast for the 2013–18 regulatory control period ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18
Opening RAB	2087.3	2282.6	2412.8	2552.8	2660.9
Capital expenditure[a]	224.7	165.4	187.6	162.9	86.9
Inflation indexation on opening RAB	52.2	57.1	60.3	63.8	66.5
Straight-line depreciation[b]	–81.7	–92.2	–107.9	–118.7	–123.4
Closing RAB	2282.6	2412.8	2552.8	2660.9	2690.9

Source: ElectraNet, *Revised revenue proposal*, p. 148.
(a) As incurred forecast, and net of disposals.
(b) Based on forecast of as-commissioned capex.

454 ElectraNet, *Revised revenue proposal*, p. 133.

5.3 Assessment approach

We did not change our assessment approach for the RAB roll forward from our draft decision. Section 7.3 of our draft decision details that approach.

5.4 Reasons for final decision

We determine ElectraNet's opening RAB value as at 1 July 2013 to be $2069.5 million. This value is $17.8 million (0.9 per cent) lower than ElectraNet's value of $2087.3 million in its revised proposal because we made the following changes to the roll forward of the RAB:

- Consistent with our draft decision, we adjusted the actual capex values rolled into the RAB to reverse the movements in capitalised provisions. This is because capitalised provisions are not capex incurred in the 2008–13 regulatory control period. Therefore, these values should not be included in the RAB until ElectraNet has paid out (incurred) the expenses to which the provisions relate. We note that ElectraNet is not disadvantaged from this adjustment because our approach ensures that employee related entitlement expenses are added to the RAB when incurred. Therefore, such costs when incurred will be recovered by ElectraNet.
- We updated the inflation input for 2012–13 using the actual March 2013 CPI published by the ABS.

We forecast ElectraNet's RAB to be $2620.3 million by 30 June 2018. This forecast represents a reduction of $70.6 million (2.6 per cent) to ElectraNet's value of $2690.9 million in its revised proposal. The main reasons for this reduction are our adjustments to:

- forecast capex (attachment 2)
- the opening RAB as at 1 July 2013 (section 5.4.1).

5.4.1 Opening RAB as at 1 July 2013

We do not accept ElectraNet's revised opening RAB as at 1 July 2013 of $2087.3 million. For this final decision, we determine the value of the opening RAB as at 1 July 2013 to be $2069.5 million. This is because ElectraNet's revised opening RAB included capitalised provisions that have not been incurred in the 2013–18 regulatory control period. For the reasons discussed below, we consider that capitalised provisions should not be included in the RAB until ElectraNet has paid out (incurred) the expenses to which the provisions relate.

In our draft decision, we adjusted ElectraNet's proposed opening RAB as at 1 July 2013 to correct input errors in the RFM. We also reduced ElectraNet's opening RAB by $3.1 million ($nominal) to reverse the amount of movements in provisions. In its revised proposal, ElectraNet adopted all aspects of our draft decision in relation to the opening RAB, except the adjustments made for movements in provisions. ElectraNet updated the forecast capex for 2011–12 with actual capex for that year in its revised RFM. It also updated its estimated capex for 2012–13 in the revised RFM.[455] We accept ElectraNet's actual capex for 2011–12. This value has been checked against regulatory accounting data for ElectraNet. We also accept ElectraNet's revision of the estimated capex for 2012–13. We consider the estimated capex amount for 2012–13 to be reasonable. This amount is slightly higher than that approved in our draft decision and reflects the best forecast available. The

[455] ElectraNet, *Revised revenue proposal*, p. 133.

financial impact of any difference between actual and estimated capex for 2012–13 will be accounted for at the next reset.[456]

Movements in provisions

ElectraNet's revised proposal did not adopt the AER's adjustment for movements in provisions. TransGrid and Transend also made submissions on the AER's treatment of provisions in the RAB in our draft decision.[457] This section sets out our considerations on the issues raised in the revised proposal and submissions in relation to the adjustment for movements in provisions.

The term 'incurred'

The NER provides that ElectraNet's RAB value as at 1 July 2008 must be increased by the amount of all capex incurred during the 2008–13 regulatory control period.[458] In our draft decision, we considered capitalised provisions should not be included in the RAB because ElectraNet has not yet paid out (incurred) the expenses to which the provisions relate. In the revised proposal, ElectraNet submitted that in our draft decision we were incorrect to equate the term 'incurred' with 'paid out'.[459]

We acknowledge that ElectraNet commonly records provisions for employee entitlements—typically, provisions for expenses such as sick leave, maternity leave, annual leave, long service leave and superannuation (accumulation and defined benefits).[460] We agree that these employee entitlements are appropriately characterised as capex to the extent that the relevant employees are engaged in ElectraNet's capital program. The issue is whether the capex was 'incurred' in the 2008–13 regulatory control period and should be rolled into ElectraNet's opening RAB.

The word 'incurred' is not a defined term under the NER or NEL. Therefore, in forming our views on this issue, we have had regard to the interpretation of 'incurred' in the context of Australian taxation law.

In its revised proposal, ElectraNet refers to *Federal Commissioner of Taxation v James Flood Proprietary Limited* (*Flood*) in interpreting 'incurred'. Specially, ElectraNet stated: [461]

> There is High Court authority that the term "incurred" does not mean only defrayed, discharged or borne, but includes encountered, run into, or fallen upon. In discussing other authorities the High Court has also noted that such authorities did not imply that a liability to pay an ascertained sum is "incurred" until the sum becomes due and payable, or that no outgoing could be "incurred" until actual payment is made.[462] To this end the AER is incorrect to equate in the Draft Decision the term "incurred" with "paid out".[463]
>
> This is not to say that expenditure that is no more than impeding, threatened or expected is "incurred".[464] Rather, once a definite commitment to the outgoing has arisen, the outgoing is "incurred".
>
> ElectraNet submits that amounts capitalised in the regulatory asset base in respect of provision for employee entitlements are to be considered relevantly "incurred" costs. The requirement to pay these

456 NER, clause S6A.2.1(f)(3).

457 TransGrid, *Submission: ElectraNet draft decision and revised revenue proposal 2012–2018*, February 2013, p. 5. Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, February 2013, pp. 8–9.

458 NER, S6A.2.1(f)(1)(i).

459 ElectraNet, *Revised revenue proposal*, p. 129.

460 ElectraNet, *Revised revenue proposal*, p. 131.

461 ElectraNet revised regulatory proposal January 2013 p.129 citing *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492 at 507.

462 ElectraNet revised regulatory proposal January 2013 p.129 citing *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492 at 507.

463 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 178.

464 ElectraNet revised regulatory proposal January 2013 p.129 citing *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492 at 507 citing *New Zealand Flax Investments v Federal Commissioner for Taxation* (1938) 61 CLR 179.

amounts and the quantum of the amounts to be paid is sufficiently certain such that the costs are to be considered “incurred”.

We do not accept ElectraNet's submission. Firstly, the Income Tax Assessment Act 1997 (ITAA97) provides that provisions for long service leave, annual leave, sick leave or other leave are not subject to a tax deduction until the employer pays those provisions to the employee to whom the leave relates.[465] This indicates that provisions for employee leave are not 'incurred' until the time in which they are paid out to the individual employees.

Secondly, the High Court decision in *Nilsen Development Laboratories Pty Ltd and Others v Federal Commissioner of Taxation* (*Nilsen*) confirms that provisions for long service leave and annual leave are not incurred until such time as the actual leave is taken.[466]

Therefore, consistent with ITAA97 and *Nilsen*, employee leave entitlements are not incurred until such time as the actual leave is taken at which time the liability would be paid and thereby 'incurred'. Therefore, we consider that capitalised provisions should not be included in the opening RAB as at 1 July 2013. This is because ElectraNet has not yet paid out (incurred) the expense to which the provision relates in the 2008–13 regulatory control period.

Australian Accounting Standards

ElectraNet submitted that the Australian Accounting Standards provide for the capitalisation of costs including amounts (such as accrued employee benefits) attributed to an asset when it is initially recognised.[467] Transend and TransGrid submitted that the AER's exclusion of provisions from the RAB does not align with the AER’s submission guidelines which require the regulatory information to be completed according to applicable Australian Accounting Standards.[468]

Both *Flood* and *Nilsen* considered that while accounting evidence shows that annual leave or long service leave should be taken up in the accounts as a liability prior to the leave itself becoming due, no deductions may be claimed for the accrued value of such leave. This is because the ordinary liability to pay wages to the employee for holidays and long service leave is not incurred, until the liability in fact arises.[469]

Therefore, we consider that ElectraNet's accounting system may be indicative, but not determinative of whether the capex has been incurred or not during the 2008–13 regulatory control period for the purposes of determining the opening RAB as at 1 July 2013.

The national electricity objective

In its revised proposal, ElectraNet submitted that the national electricity objective (NEO) would not be promoted if the correct allocation of costs is distorted as a result of the AER’s treatment of employee entitlements.[470] Transend also submitted that the AER's approach does not appear to promote the achievement of the NEO.[471]

465 *Income Tax Assessment Act 1997*, Section 26-10.
466 *Nilsen Development Laboratories Pty Ltd and Others v Federal Commissioner of Taxation* (1981) 33 ALR 161 at 165–166.
467 ElectraNet, *Revised revenue proposal*, p. 129.
468 TransGrid, *ElectraNet draft decision and revised revenue proposal 2013–2018*, February 2013, p. 5; Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, February 2013, p. 8.
469 *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492, *Nilsen Development Laboratories Pty Ltd and Others v Federal Commissioner of Taxation* (1981) 33 ALR 161.
470 ElectraNet, *Revised revenue proposal*, p. 132.
471 Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, February 2013, p. 8.

We consider that a provision should be distinguished from other liabilities because the timing and/or amount of the future expenditure required in settlement are uncertain. There can also be some uncertainty as to whether particular expense provisions will materialise in the future. Due to this uncertainty, if provisions were rolled into the RAB when the business had not actually incurred those costs, then the business would earn a return that may be different from the expense it ultimately incurs at a future date. This outcome stems from:

- the customers paying a return on capital (through charges) when the business has not yet incurred (paid out) the amount capitalised for an investment
- the business could use the cash for other investment purposes until it realises the costs.

Table 5.5 presents an example of the additional returns resulting from allowing accrued (unpaid) provisions to be rolled into the RAB. It assumes an expense of $1 million to be paid in 5 years, and is amortised over 20 years. A real WACC of 7 per cent is also assumed—that is, no inflation is assumed. The additional returns through charges were calculated by multiplying the real WACC by the capitalised provisions. The additional loss of cash flow was calculated by multiplying the real WACC by the total charges (reflecting both return on and of the capitalised provisions) resulting from the provision. The example shows returns are 22 per cent higher when provisions are included.

Therefore, we consider that allowing a TNSP to earn the return on capital and return of capital for payments that have not yet been made is not efficient or consistent with customers' long-term interests. For this reason, our decision to exclude provisions for capex which were not incurred in the 2008–13 regulatory control period is consistent with the NEO.

Table 5.5 Example: provisions for $1 million expense, due in 5 years time

Year	1	2	3	4	5
Total capitalised provisions	200,000	400,000	600,000	800,000	1,000,000
Total accumulated amortisation	10,000	30,000	60,000	100,000	150,000
Accumulated additional returns (through charges)	14,000	41,300	81,200	133,000	196,000
Accumulated additional returns (loss of cash flow)	1,680	4,991	9,884	16,310	24,220
Costs still to pay when expense becomes due					
With provisioning					850,000
Without provisioning					1,000,000
Total cost to customers					
With provisioning					1,220,220
Without provisioning					1,000,000
Difference					22%

Source: AER analysis.

AER's approach for adjusting movements in provisions

TransGrid submitted that under the NER the AER is obliged to allow recovery of efficient costs incurred by an entity. It considered that employee related costs are unavoidable, and therefore these costs should be recovered as efficient costs.[472] ElectraNet and Transend also submitted that if these accrued expenses are not recognised properly as capex, then the cash costs will be accounted for as an opex.[473]

As discussed above, we do not disagree that employee entitlements are appropriately characterised as capex to the extent that the relevant employees are engaged in undertaking a TNSP's capital program. Our approach for adjusting provisions is limited to determining when a cost in a provisions account is incurred for the purposes of determining the opening RAB. In our draft decision, we adjusted ElectraNet's actual capex by subtracting the accrued provisions (an increase in the provisions account) from the actual capex for a particular year, and adding back any cash paid out for provisions (a decrease in the provisions accounts) for that year. We carried out the same adjustment for each year of the 2008–13 regulatory control period to ensure capitalised employee entitlement provisions are rolled into the RAB when ElectraNet has paid out (incurred) those employee entitlements. Therefore, such costs when incurred are recovered by the TNSP. We consider that this approach is consistent with S6A.2.1(f)(1)(i) of the NER. It does not affect whether a provision can be capitalised. It also does not prevent a business from complying with accounting standards. Nor should it lead a business to shift costs from capex to opex because capitalised employee entitlement will be added to the RAB when incurred.

We consider maintaining accounts based on relevant accounting standards is sufficient as long as the business also reports movements in provisions. This reporting would not be onerous, in terms of either administrative effort or cost, because the TNSPs already record movements in provisions.

We acknowledge our approach to movements in provisions may create an inconsistency between the costs of internal employees and contractors, as ElectraNet submitted.[474] However, we consider a prudent TNSP should seek to outsource more of its labour costs only if it considers this approach is more cost effective than using internal labour.

In summary, we consider capitalised provisions should not be included in the RAB until ElectraNet has paid out (incurred) the expenses to which the provisions relate. Consistent with our draft decision, we adjusted ElectraNet's actual capex for 2007–08 to 2012–13 in the RFM to reverse the movements in provisions during the 2008–13 regulatory control period.[475] This adjustment reduced the revised opening RAB at 1 July 2013 by $3.1 million.

5.4.2 Forecast closing RAB as at 30 June 2018

We forecast ElectraNet's closing RAB will be $2620.3 million by 30 June 2018, which represents a reduction of $70.6 million or 2.6 per cent to ElectraNet's revised proposal of $2690.9 million.[476] This reduction reflects our final decision on the inputs for determining the forecast RAB in the PTRM. To determine the forecast RAB value for ElectraNet, we made the following amendments in the revised PTRM:

472 TransGrid, *ElectraNet draft decision and revised revenue proposal 2013–2018*, February 2013, p. 5.

473 ElectraNet, *Revised revenue proposal*, p. 132; Transend, *Submission to the AER's draft decision for ElectraNet's revenue determination*, February 2013, p. 8.

474 ElectraNet, *Revised revenue proposal*, p. 132.

475 2012–13 capex is an estimated value.

476 At the next reset, the RAB roll forward for establishing ElectraNet's opening RAB value as at 1 July 2018 will be based on actual capex during the 2013–18 regulatory control period and actual depreciation values calculated for that period.

- We reduced ElectraNet's revised forecast capex by $59.5 million or 7.9 per cent (attachment 2).
- We reduced ElectraNet's revised opening RAB as at 1 July 2013 by $17.8 million or 0.9 per cent (section 5.4.1).
- We reduced ElectraNet's revised forecast regulatory depreciation allowance by $10.6 million or 4.7 per cent (attachment 6).

5.5 Decision

Decision 5.1: We determine that ElectraNet's opening RAB as at 1 July 2013 is $2069.5 million as set out in Table 5.1.

Decision 5.2: We determine the ElectraNet's forecast opening RAB for each year of the 2013–18 regulatory control is as set out in Table 5.2.

6 Regulatory depreciation

We are required to decide on ElectraNet's indexation of the regulatory asset base (RAB) and depreciation building blocks over the 2013–18 regulatory control period.[477] We use regulatory depreciation to model the nominal asset values over the regulatory control period, and set the depreciation allowance in the annual building block revenue requirement. The regulatory depreciation allowance (or return of capital) is the net total of the straight-line depreciation (negative) amount and the amount from indexation of the RAB (positive).

This attachment sets out our final decision on ElectraNet's regulatory depreciation allowance. It also presents our final decision on the proposed depreciation schedule, including an assessment of the issues raised in ElectraNet's revised proposal. These include the standard asset life for transmission line insulator refit works and remaining asset lives used for depreciation purposes over the 2013–18 regulatory control period.

6.1 Final decision

We do not accept ElectraNet's regulatory depreciation allowance of $224.0 million ($nominal) for the 2013–18 regulatory control period in its revised proposal. We determine a regulatory depreciation allowance of $213.4 million ($nominal) for ElectraNet. Our final decision represents a reduction of $10.6 million (4.7 per cent) to ElectraNet's revised proposal, which we made for the following reasons:

- We do not accept ElectraNet's revised depreciation schedule for the ‘Transmission line refit—insulators replacement 2013–18’ asset class. We determine a standard asset life of 27 years for this asset class.
- In accepting ElectraNet's proposed weighted average method to determine the remaining asset lives, we have updated ElectraNet's remaining asset lives as at 1 July 2013. This is to reflect our adjustments to the roll forward of the RAB in the roll forward model (RFM), as discussed in attachment 5. We also adjusted the remaining asset life roll forward formula in the revised RFM to exclude input values for assets under construction.
- Consistent with our draft decision, we accept ElectraNet's proposal to accelerate the depreciation of the residual values associated with replaced assets, such as substation and communications assets, for the 2013–18 regulatory control period. However, we have reduced the amount allocated for accelerated depreciation purposes to $4.0 million from the revised $5.8 million due to several error corrections.
- Our determinations on other components of ElectraNet’s revised proposal also affect the regulatory depreciation allowance.[478] Discussed in other attachments, these determinations include the forecast capital expenditure (capex) (attachment 2) and the opening RAB as at 1 July 2013 (attachment 5).

Table 6.1 sets out our final decision on ElectraNet's annual regulatory depreciation allowance for the 2013–18 regulatory control period.

[477] NER, clauses 6A.5.4(a)(1) and (3).
[478] NER, clause 6A.6.3(a)(1).

Table 6.1 AER's final 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	78.9	89.3	104.8	116.5	119.0	508.5
Less: inflation indexation on opening RAB	51.7	56.5	59.4	62.6	64.9	295.2
Regulatory depreciation	27.1	32.8	45.4	54.0	54.1	213.4

Source: AER analysis.

6.2 ElectraNet's revised proposal

ElectraNet proposed a revised forecast regulatory depreciation allowance of $224.0 million ($nominal) over the 2013–18 regulatory control period as shown in Table 6.2. In calculating it's revised regulatory depreciation forecast, ElectraNet stated it incorporated all changes specified in the AER's draft decision, with two exceptions:[479]

- ElectraNet kept a standard life of 15 years for the ‘Transmission line refit—insulators replacement 2013–18’ asset class, rather than adopting the AER's proposed standard life of 27 years.
- ElectraNet updated remaining asset lives to reflect updates to actual capex for 2011–12 and a revised estimate of capex for 2012–13, using the AER accepted weighted average method.

Table 6.2 ElectraNet's revised proposed depreciation allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Straight line depreciation	81.7	92.2	107.9	118.7	123.4	523.9
Less: inflation indexation on opening RAB	52.2	57.1	60.3	63.8	66.5	299.9
Regulatory depreciation	29.5	35.1	47.6	54.9	56.8	224.0

Source: ElectraNet, *Revised revenue proposal*, p. 135.

6.3 Assessment approach

We did not change our assessment approach for the regulatory depreciation allowance from our draft decision. Section 8.3 of our draft decision details that approach.

6.4 Reasons for final decision

Our final decision on ElectraNet's regulatory depreciation allowance for the 2013–18 regulatory control period is $213.4 million ($nominal). This amount represents a reduction of $10.6 million ($nominal) or 4.7 per cent on ElectraNet's regulatory depreciation allowance in its revised proposal, made for the following reasons:

- We do not accept ElectraNet's revised proposal on the standard asset life for the ‘Transmission line refit—insulators replacement 2013–18’ asset class. This is because we do not consider ElectraNet's proposed standard asset life of 15 years reflects the expected economic life of the

[479] ElectraNet, *Revised revenue proposal*, p. 140.

asset type (insulators) used for the transmission line refit work for the 2013–18 regulatory control period.

- We updated the revised remaining asset lives to reflect minor formula changes made in the 'Remaining asset lives roll forward' sheet in the RFM and our final decision on the roll forward of the opening RAB (discussed in attachment 5).
- We reduced the amount allocated for accelerated depreciation purposes to $4.0 million from $5.8 million due to several error corrections to ElectraNet's revised forecast.

6.4.1 Standard asset life for—'Transmission line refit—insulators replacement 2013–18' asset class

We do not accept ElectraNet's revised proposal on the standard asset life of 15 years for the 'Transmission line refit—insulators replacement 2013–18' asset class. We have assigned a standard asset life of 27 years for this asset class. For the reasons discussed below, we consider that this asset life reflects the economic life of the insulators used in the refit works. In turn, we consider that this standard asset life creates a depreciation profile that reflects the nature of the underlying assets over the economic life of the assets within this asset class.[480]

In our draft decision, we considered:[481]

- ElectraNet's approach for determining the standard asset life underestimated the economic life of the insulators being replaced as part of the transmission line refurbishment capex
- the appropriate standard asset life for this asset class should be 27 years, which reflects the weighted average of the technical lives of the insulators used for the forecast transmission line refurbishment works.

In its revised proposal, ElectraNet did not adopt the standard asset life of 27 years. ElectraNet stated that the AER's draft decision was implicitly based on two assumptions:[482]

1. Once underlying transmission assets are decommissioned, the insulators can be redeployed elsewhere, and therefore have a continuing useful economic life; or
2. The economic life of the underlying transmission line assets will be extended so that the refitted insulators will continue to provide services throughout their expected technical life.

ElectraNet stated that its engineering assessment shows the redeployment of the insulators is not an economic option. It also submitted that it is speculative to assume that the underlying line assets will exceed their remaining economic life, because there is no engineering basis for this assessment at this point in time.[483]

We agree with ElectraNet that when the underlying transmission assets are decommissioned, reusing those insulators may not be cost effective, given the high labour costs and other costs of redeployment. However, we consider it reasonable to expect that ElectraNet could extend the

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

481 AER, *Draft decision: ElectraNet transmission determination, November 2012*, pp. 185–7. In our draft decision, we also changed the name of this asset class to 'Transmission line refit—insulators replacement 2013–18' from 'Transmission lines refit' to better represent the nature of the forecast transmission line refurbishment capex for the 2013–18 regulatory control period. In its revised proposal, ElectraNet adopted the name change suggested in our draft decision.

482 ElectraNet, *Revised revenue proposal*, p. 137.

483 ElectraNet, *Revised revenue proposal*, pp. 137–8.

economic life of the underlying transmission line assets over time so that the insulators could be in service until the end of their expected technical lives, for the following reasons:

- The main benefit of ElectraNet's move from an age-based asset management strategy to a condition-based asset management strategy is the ability to extend asset lives beyond their expected technical specifications in general. EMCa noted condition-based maintenance strategies on a worldwide basis have been highly successful in extending transmission tower asset lives, even using significantly less sophisticated condition-based maintenance strategies than that being used by ElectraNet.[484] The Energy Consumers Coalition of South Australia (ECCSA) submitted that the transmission line refit works (insulator replacement) would likely extend the overall life of the underlying transmission line assets.[485]

- ElectraNet's economic case to replace those insulators is only justified if it can be confident that the tower structures of the lines can have their asset lives reasonably extended to the expected life of the insulators replaced. The insulators that ElectraNet proposed to use for the line refurbishment works have technical lives of 20 and 40 years.[486] ElectraNet proposed to use insulators with a 40 year technical life on five of the six lines forecast to be refitted in the 2013–18 regulatory control period.[487] EMCa considered the selection of these insulator types suggests ElectraNet expects to achieve more than 20 years life from the insulators.[488] However, the proposed 15 year economic life is much shorter than the technical life of the insulators that ElectraNet is proposing to use for the refit works.

Therefore, we consider the expected economic life of the insulators should be much longer than the proposed 15 years because we expect the insulators should, in general, continue to be in service until the end of their technical lives.

Further, we note that if ElectraNet cannot extend the lives of specific underlying assets through its asset management strategies, then it could propose to write off the residual value of the insulators when the underlying line assets are decommissioned. However, ElectraNet should take this approach on a case-by-case basis for particular assets, rather than uniformly shortening the lives of all insulators for the 'Transmission line refit—insulators replacement 2013–18' asset class to 15 years.

For these reasons, we consider that ElectraNet's proposed standard asset life of 15 years does not reflect the expected economic life of the assets within this asset class. Consistent with our draft decision, we calculated a weighted average of the standard asset life of 27 years by weighting together the technical lives of the insulators using the proportion of capex for each insulator type as weights. We consider that a standard asset life of 27 years results in a depreciation profile that reflects the nature of the assets over the economic life of the assets within this asset class.[489]

Table 6.3 sets out our final decision on ElectraNet's standard asset lives for the 2013–18 regulatory control period.

6.4.2 Remaining asset lives at 1 July 2013

ElectraNet revised its remaining asset lives as at 1 July 2013 using the accepted weighted average method in our draft decision.[490] For this final decision, we have updated the revised remaining asset

[484] EMCa, *ElectraNet technical review – revised revenue proposal*, April 2013, p. 91, paragraph 371.
[485] ECCSA, *Submission on AER draft decision ElectraNet Determination 2013-18*, February 2013, pp. 14–5.
[486] ElectraNet, *Email response to information request AER RP 15, Transmission line refit*, ENET230, 15 August 2012, p. 3.
[487] This accounts for about 36 per cent of the total transmission line refit capex for the 2013–18 regulatory control period.
[488] EMCa, *ElectraNet technical review – revised revenue proposal,* April 2013, p. 92, paragraph 374.
[489] NER, clause 6A.6.3(b)(1).
[490] ElectraNet, *Revised revenue proposal*, p. 139.

lives to reflect our adjustments to ElectraNet's actual capex in the RFM, as discussed in attachment 5. This is because the actual capex values are inputs for calculating the weighted average remaining asset lives in the RFM.

In our draft decision, we adjusted ElectraNet's proposed inputs to the RFM and accordingly, updated the remaining asset lives at 1 July 2013. ElectraNet's revised proposal adopted all of these adjustments in the RFM, except the adjustment for movements in provisions. It also continued to apply the weighted average method to calculate the remaining economic lives as accepted by us in our draft decision.[491]

ECCSA noted ElectraNet's revised remaining asset lives as at 1 July 2013 are either equal to or less than the values determined by us in our draft decision.[492] We note that this discrepancy is largely due to ElectraNet's revised RFM not incorporating a formula change that we made in our draft decision RFM. In our draft decision, we adjusted the remaining asset life roll forward formula in the RFM to exclude the input value for assets under construction.[493] This adjustment was necessary because the remaining asset life roll forward calculation of the opening RAB capital stream should reflect only as-commissioned assets. We highlighted this adjustment in our draft decision RFM.[494]

For this final decision, we accept ElectraNet's revised proposal on the weighted average method to calculate the remaining economic lives at 1 July 2013. However, consistent with our draft decision, we adjusted the remaining asset life roll forward formula in the revised RFM to exclude input values of assets under construction. We also updated ElectraNet's remaining economic lives at 1 July 2013, based on our final decision on the roll forward of the opening RAB (attachment 5).

Table 6.3 sets out our final decision on ElectraNet's remaining asset lives at 1 July 2013 for the 2013–18 regulatory control period.

491 ElectraNet, *Revised revenue proposal*, p. 139.
492 ECCSA, *Submission on AER draft decision ElectraNet Determination 2013–18*, February 2013, p. 15.
493 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 187.
494 AER, *Draft decision—ElectraNet's roll forward model*, November 2012, 'Asset roll forward' sheet.

Table 6.3 AER's final decision on ElectraNet's standard asset lives and remaining asset lives at 1 July 2013 (years)

Asset class	Standard asset life	Remaining asset life at 1 July 2013
Commercial buildings	30.0	23.3
Communications—civil	55.0	44.7
Communications—other	15.0	11.7
Computers, software, and office machines	4.0	3.5
Easement	n/a	n/a
Land	n/a	n/a
Network switching centres	5.0	0.8
Office furniture, movable plant, and miscellaneous	10.0	9.0
Refurbishment [a]	10.0	4.4
Substation primary plant	44.8	33.0
Substation demountable buildings	15.0	14.5
Substation establishment	55.0	53.6
Substation fences	35.0	35.0
Substation secondary systems—electromechanical	27.0	17.2
Substation secondary systems—electronic	15.0	14.1
Transmission lines—overhead	55.0	30.2
Transmission lines—underground	40.0	36.5
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	27.0	n/a

Source: AER analysis
n/a: Not applicable.
(a) Refurbishment projects for the 2003–08 regulatory control period.

6.4.3 Accelerated depreciation

Consistent with our draft decision, we accept ElectraNet's proposal to accelerate the depreciation of the residual values associated with replaced assets for the 2013–18 regulatory control period. However, we have reduced the amount allocated for accelerated depreciation purposes to

$4.0 million from $5.8 million to reflect several adjustments to ElectraNet's revised accelerated depreciation value.[495]

In our draft decision, we reduced the amounts allocated for accelerated depreciation purposes to $3.6 million to reflect the reductions to ElectraNet's proposed forecast replacement capex.[496] However, ElectraNet did not adopt this adjustment or comment on this matter in its revised proposal.

In its response to our information request, ElectraNet clarified that it had incorrectly calculated the forecast accelerated depreciation input value in the revised RFM (and PTRM). It submitted that the correct forecast should be $4.0 million.[497] We have reviewed the submission and accept the adjustments made by ElectraNet to derive the corrected forecast value. Therefore, we have amended the forecast accelerated depreciation amount in the RFM (and PTRM) to reflect the corrected $4.0 million.

6.5 AER decision

Decision 6.1: We determine ElectraNet's forecast regulatory depreciation allowance to be $213.4 million ($nominal) over the 2013–18 regulatory control period, as set out in Table 6.1.

Decision 6.2: We determine ElectraNet's standard asset lives and remaining asset lives as at 1 July 2013 to be those as set out in Table 6.3.

495 ElectraNet, *Response to AER information request AER RP 16: CAPEX impact of AEMO's 2012 demand forecast ENET238*, August 2012.

496 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 180.

497 ElectraNet, *Response to AER information request AER RRP 21: Accelerated depreciation*, ENET372, 11 April 2013.

7 Corporate income tax

We are required to make a decision on the estimated cost of corporate income tax.[498] Under the post tax framework, a corporate income tax allowance is calculated as part of the building block assessment using our post tax revenue model (PTRM).

This attachment sets out our final decision on ElectraNet's proposed corporate income tax allowance for the 2013–18 regulatory control period. It also presents our assessment of issues raised in ElectraNet's revised proposal. These include 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.

7.1 Final decision

We do not accept ElectraNet's estimated cost of corporate income tax allowance of $28.1 million ($nominal) for the 2013–18 regulatory control period as set out in its revised proposal. We determine the estimated corporate income tax allowance for ElectraNet to be $29.3 million ($nominal), which represents an increase of $1.2 million (or 4.3 per cent) to the revised proposal. This increase has been made for the following reasons:

- We do not accept ElectraNet's revised opening TAB as at 1 July 2013 of $1352.8 million. This is due to the adjustments we made to the actual capex in the roll forward model (RFM) as discussed in attachment 5.

- We accept the majority of ElectraNet's revised standard tax asset lives for its asset classes, except for the 'Transmission line refit—insulators replacement 2013–18' asset class. We changed the revised standard tax asset life for this asset class to 27 years from 15 years to be consistent with our final decision on the standard asset life for this asset class for regulatory depreciation purposes.

- We accept ElectraNet's weighted average method to calculate the remaining tax asset lives at 1 July 2013 in its revised proposal. This weighted average method was accepted in our draft decision.[499] For this final decision, we have updated the proposed remaining tax asset lives to reflect our adjustments to ElectraNet's actual capex for 2007–08 to 2012–13 in the RFM.[500]

- Our determinations on other building blocks including forecast operating expenditure (opex) (attachment 3) and cost of capital (attachment 4) also impact the estimated corporate income tax allowance.[501]

Based on the approach to modelling the cash flows in the PTRM, we have derived an effective tax rate of 23.5 per cent for this final decision.

Table 7.1 sets out our final decision on ElectraNet's estimated corporate income tax allowance over the 2013–18 regulatory control period.

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498 NER, clauses 6A.5.4(a)(4).
499 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 190.
500 2012–13 capex is an estimated value.
501 NER, clause 6A.6.4.

Table 7.1 AER's final decision on ElectraNet's corporate income tax allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Tax payable	14.9	16.1	17.0	19.0	16.7	83.7
Less: value of imputation credits	9.7	10.4	11.1	12.3	10.9	54.4
Net corporate income tax allowance	5.2	5.6	6.0	6.6	5.9	29.3

Source: AER analysis.

7.2 ElectraNet's revised proposal

As is shown in Table 7.2, ElectraNet proposed a revised corporate income tax allowance of $28.1 million ($nominal) over the 2013–18 regulatory control period. ElectraNet stated that it has incorporated all aspects of the AER's draft decision, with the exception of:[502]

- the standard tax asset life for the transmission line refit class—ElectraNet has included in its revised proposal a standard tax life of 15 years for this asset class
- the opening TAB value as at 1 July 2013—ElectraNet has revised the opening TAB as at 1 July 2013 to reflect the adjustments to the capex inputs in its revised RFM
- remaining tax asset lives at 1 July 2013—in accordance with the accepted weighted average method, ElectraNet updated its remaining tax asset lives as at 1 July 2013 to reflect its actual capex for 2011–12 included in the roll forward of the regulatory asset base (RAB) in the RFM.

ElectraNet's revised corporate income tax allowance also reflects its revised forecast capex.

Table 7.2 ElectraNet's revised proposed corporate income tax allowance ($ million, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Tax payable	14.4	15.4	16.4	18.0	15.9	80.2
Less: value of imputation credits	9.4	10.0	10.7	11.7	10.4	52.2
Net corporate income tax allowance	5.1	5.4	5.7	6.3	5.6	28.1

Source: ElectraNet, *Revised revenue proposal*, p. 147.

7.3 Assessment approach

We did not change our assessment approach for the corporate income tax allowance from our draft decision. Section 9.3 of our draft decision details that approach.

7.4 Reasons for final decision

Our final decision on ElectraNet's forecast corporate income tax allowance is $29.3 million ($nominal). This represents an increase of $1.2 million ($nominal) or 4.3 per cent on ElectraNet's corporate income tax allowance in its revised proposal. This increase has been made for the following reasons:

[502] ElectraNet, *Revised revenue proposal*, pp. 142 and 146.

- we changed the revised standard tax asset life for the ‘Transmission line refit—insulators replacement 2013–18’ asset class to 27 years from 15 years. This is to achieve consistency with our final decision on the standard asset life for this asset class for regulatory depreciation purposes
- we updated the proposed remaining tax lives to reflect our adjustments to ElectraNet's actual capex for 2007–08 to 2012–13 in the RFM[503]
- our determinations on other building blocks including forecast opex (attachment 3) and cost of capital (attachment 4) also impact the estimated corporate income tax allowance.[504]

7.4.1 Tax asset base as at 1 July 2013

We do not accept ElectraNet's revised opening TAB as at 1 July 2013 of $1352.8 million. For this final decision, we determine the value of the opening TAB as at 1 July 2013 to be $1351.0 (nominal), a decrease of $1.8 million (or 0.1 per cent) on the revised proposal.

In our draft decision we accepted ElectraNet's proposed method to establish the opening TAB as at 1 July 2013. However, we also increased the proposed value of the opening TAB to correct minor input errors and adjust ElectraNet's actual capex values for movements in provisions in the RFM.[505] ElectraNet's revised RFM did not incorporate the adjustments for movements in provisions in the revised RFM. ElectraNet also updated the 2011–12 capex with actual values and revised 2012–13 estimated capex value in the RFM for its revised proposal.[506]

Consistent with our draft decision, we have adjusted ElectraNet's actual capex in the 2008–13 regulatory control period to reverse the movements in provisions for the purposes of rolling forward the RAB and the TAB. Our reasons for this decision are discussed in section 5.4.1 of attachment 5. This adjustment slightly decreases the revised opening TAB as at 1 July 2013 because the actual capex values are inputs for calculating the opening TAB.

Table 7.3 sets out our final decision on ElectraNet's TAB roll forward for the 2008–13 regulatory control period.

Table 7.3 AER's final decision on ElectraNet's tax asset base roll forward ($ million, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13
Opening tax asset base	874.4	902.2	890.3	948.0	1212.0
Capital expenditure[a]	56.2	19.3	90.6	301.7	186.6[b]
Tax depreciation	–28.4	–31.2	–32.9	–37.7	–47.6
Closing tax asset base	902.2	890.3	948.0	1212.0	1351.0

Source: AER analysis.
(a) As commissioned, net of disposals.
(b) Based on estimated capex.

503 2012–13 capex is an estimated value.
504 NER, clause 6A.6.4.
505 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 190.
506 ElectraNet, *Revised revenue proposal*, p. 142.

7.4.2 Standard tax asset lives

We do not accept ElectraNet's revised standard tax asset life of 15 years for the 'Transmission line refit—insulators replacement 2013–18' asset class. We consider a standard tax asset life of 27 years for this asset class provides a more accurate estimate of the tax depreciation amount for a benchmark efficient TNSP as required by the NER.[507]

In our draft decision, we considered the standard tax asset life for this asset class should reflect the same standard life of the asset used for regulatory depreciation purposes. ElectraNet adopted this approach. However, ElectraNet submitted that the standard asset life used for regulatory depreciation purposes for this asset class should be 15 years. It therefore also submitted that the standard tax asset life should be 15 years.[508]

As discussed in attachment 6, for regulatory depreciation purposes we have determined a standard asset life of 27 years for ElectraNet's 'Transmission line refit—insulators replacement 2013–18' asset class. Therefore, we have amended the revised standard tax asset life for this asset class in our final decision.

Table 7.4 sets out our final decision on ElectraNet's standard tax asset lives for the 2013–18 regulatory control period.

7.4.3 Remaining tax asset lives at 1 July 2013

In accordance with our draft decision, ElectraNet revised its remaining tax asset lives as at 1 July 2013 using the accepted weighted average method. For this final decision, we have updated the revised remaining tax asset lives to reflect our adjustments to ElectraNet's 2007–08 to 2012–13 actual capex in the RFM.[509] This adjustment was made because the actual capex values are inputs for calculating the weighted average remaining tax asset lives in the RFM.

Table 7.4 sets out our final decision on ElectraNet's remaining tax asset lives as at 1 July 2013 for the 2013–18 regulatory control period.

507 NER, clause 6A.6.4(a)(2).

508 ElectraNet, *Revised revenue proposal*, p. 143.

509 The reasons for our adjustments on the 2007–08 to 2012–13 actual capex values are discussed in attachment 5. 2012–13 capex is an estimated value.

Table 7.4 AER's final decision on ElectraNet's 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 as at 1 July 2013 (years)
Commercial buildings	40.0	30.9
Communications—civil	12.5	38.1
Communications—other	12.5	10.7
Computers, software, and office machines	3.3	2.8
Easement	n/a	n/a
Land	n/a	n/a
Network switching centres	4.0	3.5
Office furniture, movable plant, and miscellaneous	12.8	11.8
Refurbishmentb	43.8	31.3
Substation primary plant	40.0	32.9
Substation demountable buildings	40.0	39.4
Substation establishment	40.0	38.7
Substation fences	40.0	40.0
Substation secondary systems—electromechanical	12.5	18.4
Substation secondary systems—electronic	12.5	11.7
Transmission lines—overhead	47.5	26.4
Transmission lines—underground	47.5	44.1
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	27.0	n/a

Source: AER analysis.
n/a: not applicable.

7.5 AER decision

Decision 7.1: We determine ElectraNet's estimated cost of corporate income tax allowance to be $29.3 million ($nominal) over the 2013–18 regulatory control period, as set out in Table 7.1.

Decision 7.2: We determine ElectraNet's total opening TAB as at 1 July 2013 to be $1351.0 million ($nominal), as set out in Table 7.3.

Decision 7.3: We determine 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 7.4.

8 Maximum allowed revenue

This attachment sets out the AER's final 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:[510]

- 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.

We determine ElectraNet's annual building block revenue requirement using a building block approach and the X factors by smoothing the annual building block revenue requirement over the 2013–18 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.

8.1 Final decision

Our determinations on ElectraNet's proposed building block components have a consequential impact on the annual building block revenue requirement. We have recalculated the X factor and the annual expected MAR to reflect our final decision on ElectraNet's annual building block revenue requirement.

For this final decision, we approve an estimated total revenue cap of $1577.5 million ($nominal) for ElectraNet for the 2013–18 regulatory control period.[511] Our approved X factor is –2.69 per cent per annum from 2014–15 to 2017–18.[512]

Table 8.1 sets out our final 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.

510 NER, clauses 6A.4.2(a)(1)–(3) and 6A.6.8.

511 The estimated total revenue cap is equal to the total of the annual expected MAR over the 2013–18 regulatory control period.

512 Consistent with ElectraNet's revised proposal, we have determined a constant X factor to apply over the 2013–18 regulatory control period.

Table 8.1 AER's final 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	155.2	169.5	178.2	187.8	194.7	885.3
Regulatory depreciation[a]	27.1	32.8	45.4	54.0	54.1	213.4
Operating expenditure	81.8	87.0	90.8	96.9	100.0	456.5
Efficiency benefit sharing scheme (carryover amounts)	–1.3	–3.6	– 1.4	0.0	4.8	–1.5
Net tax allowance	5.2	5.6	6.0	6.6	5.9	29.3
Annual building block revenue requirement (unsmoothed)	268.1	291.3	319.0	345.2	359.4	1583.0
Annual expected MAR (smoothed)	284.0	298.9	314.7	331.2	348.7	1577.5[b]
X factor (%)	n/a[c]	–2.69	–2.69	–2.69	–2.69	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 final decision. The MAR for 2013–14 is around 14.6 per cent lower than the MAR in the final year of the 2008–13 regulatory control period (2012–13) in real dollar terms, or 12.5 per cent lower in nominal dollar terms.

8.2 ElectraNet's revised proposal

Based on its revised building block components, ElectraNet proposed a total revenue cap of $1608.8 million ($nominal) for the 2013–18 regulatory control period. Table 8.2 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 8.2 ElectraNet's revised proposed annual building block 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	148.5	162.4	171.6	181.6	189.3	853.4
Regulatory depreciation	29.5	35.1	47.6	54.9	56.8	224.0
Operating expenditure	92.4	100.3	103.1	105.2	107.9	508.9
Efficiency benefit sharing scheme (carryover amounts)	–0.6	–2.5	–1.9	0.0	4.4	–0.6
Net tax allowance	5.1	5.4	5.7	6.3	5.6	28.1
Annual building block revenue requirement (unsmoothed)	274.9	300.6	326.2	348.1	364.0	1613.8
Annual expected MAR (smoothed)	291.7	306.0	321.0	336.8	353.3	1608.8
X factor (%)	n/a	–2.35	–2.35	–2.35	–2.35	n/a

Source: ElectraNet, *Revised revenue proposal*, pp. 150–151.

8.3 Assessment approach

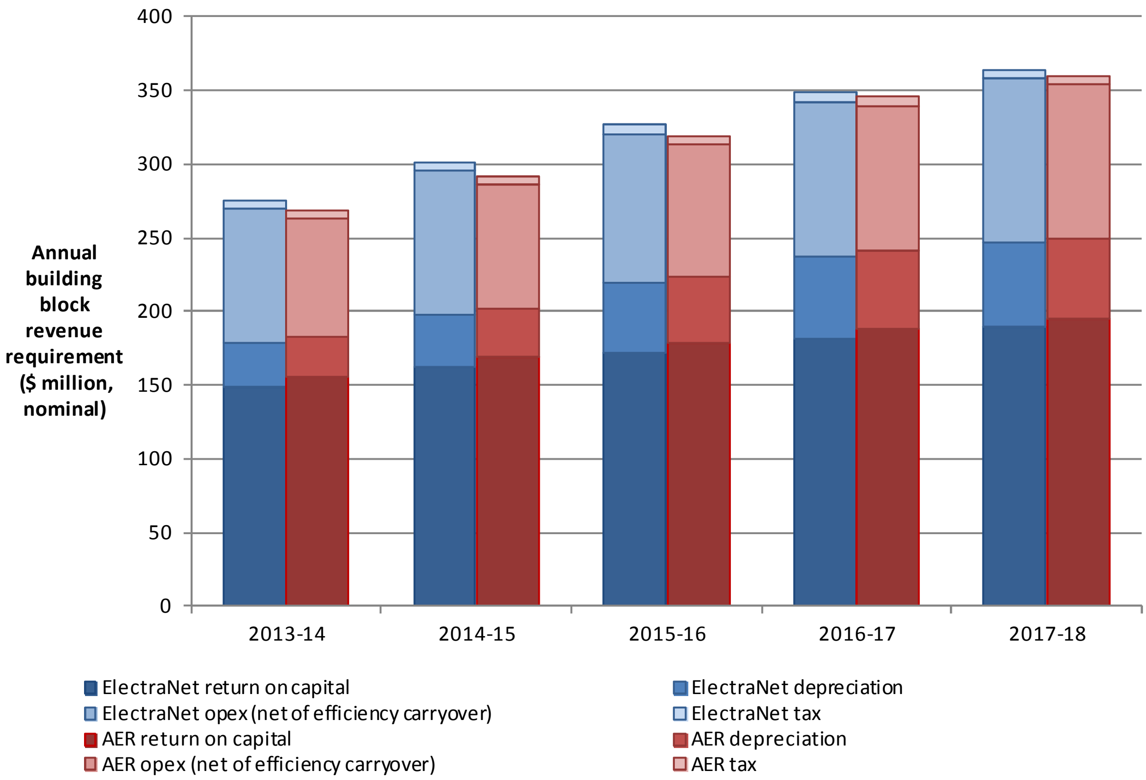
We did not change our assessment approach for the MAR from our draft decision. Section 10.3 of our draft decision details that approach.

8.4 Reasons for final decision

For this final decision, we determine a total annual building block revenue requirement of $1583.0 million ($nominal) for ElectraNet for the 2013–18 regulatory control period. This compares to ElectraNet's total annual building block revenue requirement of $1613.8 million ($nominal) for this period in its revised proposal.[513]

Figure 8.1 shows the components from our determination 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 revised proposal.

Figure 8.1 AER's final decision and ElectraNet's revised proposed annual building block revenue requirement ($ million, nominal)



Source: AER analysis.

We have calculated the annual building block revenue requirement for ElectraNet based on our final decision on these building block components. The revenues were affected by the changes we made to ElectraNet's revised building block components. These changes include:

- forecast operating expenditure (attachment 3)
- the cost of capital (attachment 4)

[513] ElectraNet, *Revised revenue proposal*, p. 151.

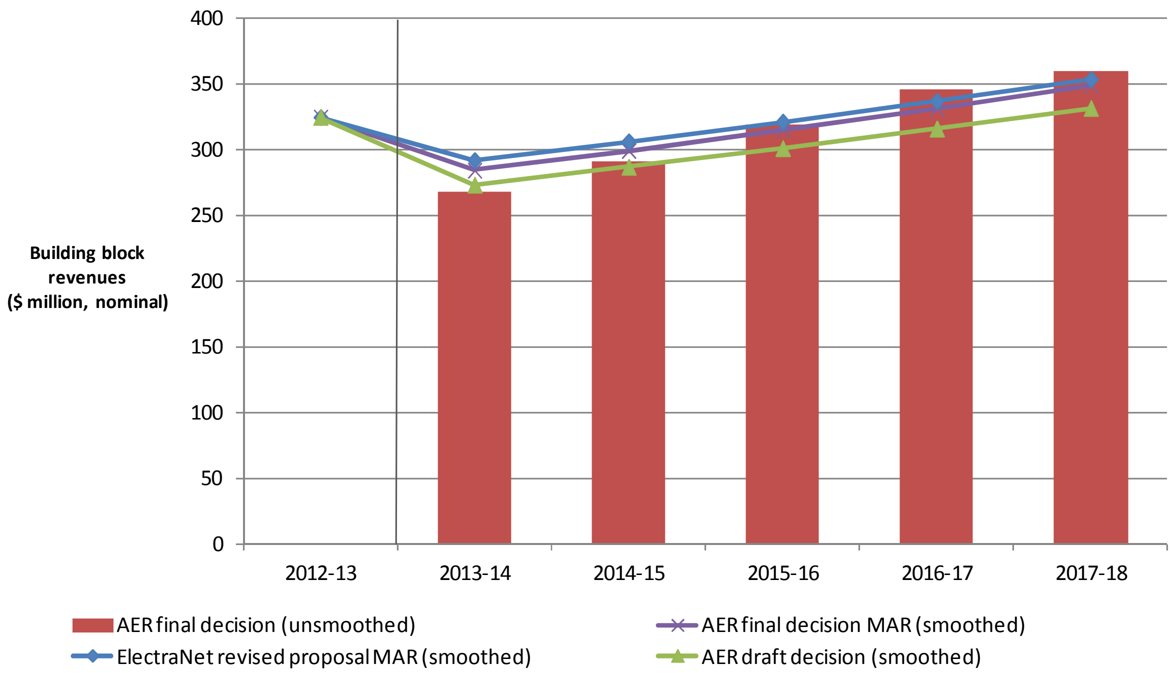
- the opening RABs over the 2013–18 regulatory control period (attachment 5)
- forecast regulatory depreciation (attachment 6)
- the estimated cost of corporate income tax (attachment 7).

8.4.1 X factor, annual expected MAR and estimated total revenue cap

ElectraNet incorporated the methodology we used in our draft decision regarding the smoothing of the MAR.[514] For this final decision, we have determined a revised X factor of –2.69 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 $1267.1 million ($nominal) as at 1 July 2013. Based on this net present value and applying the CPI–X method, we have determined the annual expected MAR (smoothed) for ElectraNet that increases from $284.0 million in 2013–14 to $348.7 million in 2017–18 ($nominal).

The resulting estimated total revenue cap for ElectraNet that we have approved is $1577.5 million ($nominal) for the 2013–18 regulatory control period. Figure 8.2 shows our final 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 8.2 AER's final decision on ElectraNet's annual expected MAR (smoothed) and annual building block revenue requirement (unsmoothed) ($ million, nominal)



Source: AER analysis.

To determine the expected MAR over the 2013–18 regulatory control period, we have set the MAR for the first regulatory year (2013–14) at $284.0 million ($nominal). This is higher than the annual building block revenue requirement for 2013–14, which is $268.1 million ($nominal).[515] We then applied an X factor of –2.69 per cent per annum to determine the expected MAR in subsequent years. We consider that this profile of X factors results in an expected MAR in the last year of the

514 ElectraNet, *Revised revenue proposal*, p. 151.

515 The MAR for the last year of the 2008–13 regulatory control period (2012–13) is approximately $324.5 million.

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.[516]

We have considered stakeholder submissions, which raised concerns with the impact of ElectraNet's revenue determination on the expected electricity price.[517] We have smoothed the estimated total revenue cap as much as possible, consistent with the requirements of the NER and NEL.

The average increase in our approved expected MAR for ElectraNet is 1.7 per cent per annum ($nominal) over the 2013–18 regulatory control period. This consists an initial decrease of 12.5 per cent from 2012–13 to 2013–14 and a subsequent average annual increase of 5.3 per cent during the remainder of the 2013–18 regulatory control period.[518] Our final 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, increased labour costs and increased field maintenance works
- increased regulatory depreciation allowance due to growth in the RAB.

8.4.2 Indicative average transmission price impact

The NER does not require us to estimate transmission price changes for a revenue determination of a TNSP. Nonetheless, we typically provide some indicative transmission price impacts flowing from the revenue determination. Although we assess ElectraNet's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by us. ElectraNet establishes its transmission charges in accordance with its approved pricing methodology and the NER.[519]

We estimate the effect of the final 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),[520] and
- dividing it by the forecast annual energy delivered in South Australia.[521]

Based on this approach, we estimate that this final decision will result in a slight increase in average transmission charges of 0.8 per cent per annum ($nominal) from 2012–13 to 2017–18. This estimated increase in average transmission charges is due to the average increase in our approved MAR being higher than the average increase in forecast annual energy delivered in South Australia over the 2013–18 regulatory control period. The average increase in our approved MAR for South Australia is 1.7 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.

516 NER, clause 6A.6.8(c)(2). We consider 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 profile of X factors we determined, this divergence is 3 per cent.

517 EUAA, *Submission to the AER on ElectraNet's revenue draft determination 2013/14 to 2017/18*, February 2013, pp. 9–10.

518 In real terms ($2012–13), the average decrease in our approved expected MAR for ElectraNet is 0.8 per cent per annum over the 2013–18 regulatory control period. This consists an initial decrease of 14.6 per cent from 2012–13 to 2013–14 and a subsequent average annual increase of 2.7 per cent during the remainder of the 2013–18 regulatory control period.

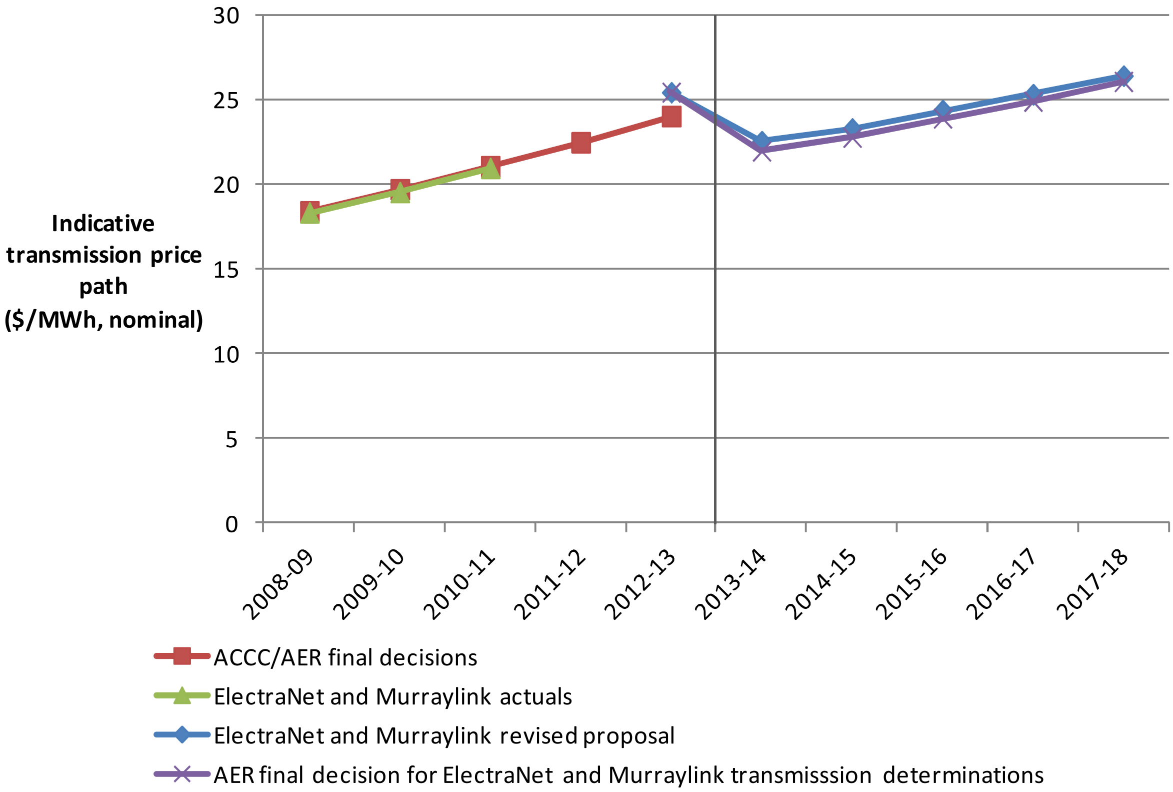
519 NER, clause 6A.24.1(d).

520 Murraylink, *Pricing methodology*, May 2012, p. 3.

521 AEMO, *National electricity forecasting report*, August 2012, table 6-1, Medium (Scenario 3, planning).

Figure 8.3 shows the indicative average transmission charges resulting from our final 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 increase from around $25.4 per MWh in 2012–13 to $26.0 per MWh in 2017–18.

Figure 8.3 Indicative transmission price path from 2008–09 to 2017–18 ($/MWh, nominal)



Source: AER analysis.

We estimate that the final decision will result in slightly lower transmission charges on average over the 2013–18 regulatory control period compared to ElectraNet and Murraylink's revised proposals. 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. If the transmission charges based on our final decision are to pass through to end customers, a typical residential bill could be expected to increase by up to $4 in total ($nominal) during the 2013–18 regulatory control period.[522] In comparison, ElectraNet's and Murraylink's revised proposals would result in an average residential bill increase of approximately $6 in total.

Similarly, if the transmission charges arising from this final decision are to pass through to end customers, a typical non-residential bill could be expected to increase by up to $7 in total ($nominal) during the 2013–18 regulatory control period.[523] In comparison, ElectraNet's and

[522] Based on an average South Australian residential electricity customer bill of $1800 ($nominal, excluding GST) in 2012–13, which reflect 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.

[523] Based on an average South Australian non-residential customer bill of $3457 ($nominal, excluding GST) in 2012–13, which reflect 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.

Murraylink's revised proposals would result in an average non-residential bill increase of approximately $11 in total.

8.5 AER decision

Decision 8.1: We determine 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 to be as set out in Table 8.1.

Decision 8.2: We determine ElectraNet's annual adjustment process for the MAR over the 2013–18 regulatory control period to be as set out in the transmission determination for ElectraNet for the 2013–18 regulatory control period.

9 Service target performance incentive scheme

This attachment sets out the AER's final decision on ElectraNet's proposed parameter values and weightings for the service target performance incentive scheme (STPIS).[524] The STPIS comprises two components: a service component and a market impact component. This attachment deals with each component separately.

9.1 Final decision

Service component

We do not accept ElectraNet's revised proposal service component parameter weightings. Table 9.1 shows our final decision on ElectraNet's proposed values and weightings for the service component.

Table 9.1 AER's final decision on ElectraNet's parameter values and revenue 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 (mins)				
Average outage duration	323.2	203.2	83.2	0.2
Total				1.0

Market impact component

Table 9.2 shows our final decision on ElectraNet's market impact component values and weighting.

Table 9.2 AER final decision on ElectraNet's parameter values and revenue weighting for the market impact component of the STPIS

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

[524] The STPIS is established by clause 6A.7.4 of the NER.

9.2 ElectraNet's revised proposal

Service component

ElectraNet did not adopt our draft decision on the weightings to apply to the 'average outage duration' parameter and the 'loss of supply events > 0.05 system minutes' sub–parameter. However, it incorporated all other aspects of our draft decision in its revised revenue proposal.

Market impact component

ElectraNet incorporated our draft decision target of 1588 dispatch intervals into its revised revenue proposal.

9.3 Assessment approach

We have applied the same assessment approach as set out in section 11.3 of our draft decision.[525]

9.4 Reasons for final decision

9.4.1 Service component

We do not accept ElectraNet's revised proposal to increase the revenue weighting for the 'average outage duration' parameter because:

- the current revenue weighting incentivised an improvement in ElectraNet's 'average outage duration' performance
- ElectraNet did not justify an increased weighting for the parameter
- an increased weighting for the 'loss of supply events > 0.05 system minutes' sub–parameter is warranted given ElectraNet's 2010–12 performance was poorer than its 2008–09 performance.

Weightings for service component parameters

In our draft decision, we agreed with ElectraNet that it was appropriate to reduce the revenue weighting for the 'critical circuit availability peak' sub–parameter from 0.2 to 0.1 per cent of maximum allowed revenue (MAR). As the total revenue at risk under the service component must be 1 per cent, we then had to add an additional 0.1 per cent of revenue weighting to another parameter.[526] We did not accept ElectraNet's proposal to increase the 'average outage duration' revenue weighting from 0.2 to 0.3 per cent. Instead, we increased the 'loss of supply events > 0.05 system minutes' sub–parameter weighting from 0.1 to 0.2 per cent.[527]

'Average outage duration' parameter

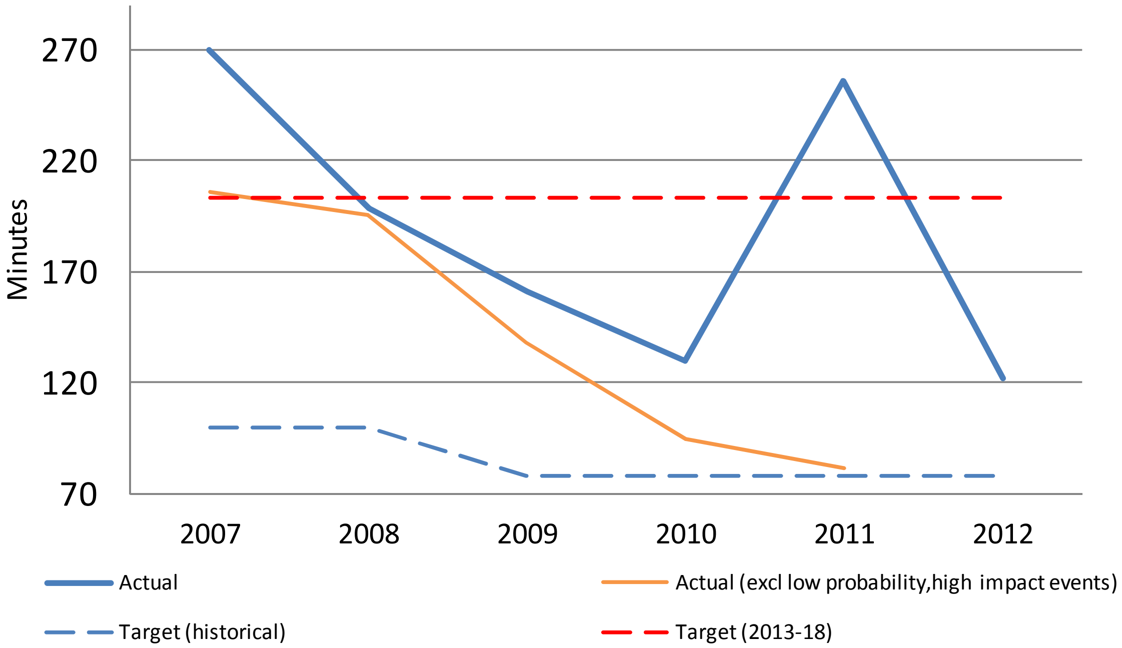
The STPIS incentivises the improvement and maintenance of service performance via the cap, collar, performance target and revenue weighting values for each parameter. Together, these values determine the strength of the incentive to improve and maintain performance for a certain parameter. ElectraNet's proposal to increase the revenue weighting for the 'average outage duration' parameter

[525] AER, *Draft decision: ElectraNet transmission determination, November 2012*, pp. 211–213.
[526] AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme*, March 2011, clauses 3.4 and 3.5.
[527] AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 218.

would result in a stronger incentive to improve and maintain its 'average outage duration' performance.

Figure 9.1 illustrates ElectraNet's 'average outage duration' performance over the past six years.

Figure 9.1 ElectraNet's '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; ElectraNet, *2012 service standards submission*, 1 February 2013; AER analysis.

This figure shows ElectraNet would have received a financial reward for four of the last six years if the new targets had been in place. It also illustrates a clear improvement in ElectraNet's 'average outage duration' performance over the 2008–13 regulatory control period. This trend is even more pronounced when the effect of low probability and high impact events are removed, as shown by the orange line in Figure 9.1. This indicates that the current incentive, partly determined by the revenue weighting, is sufficient to incentivise improvements in ElectraNet's 'average outage duration' performance. For this reason, ElectraNet should provide clear evidence or reasons to show that an increase in the weighting for this parameter is necessary to improve and maintain 'average outage duration' performance. ElectraNet did not provided this justification.

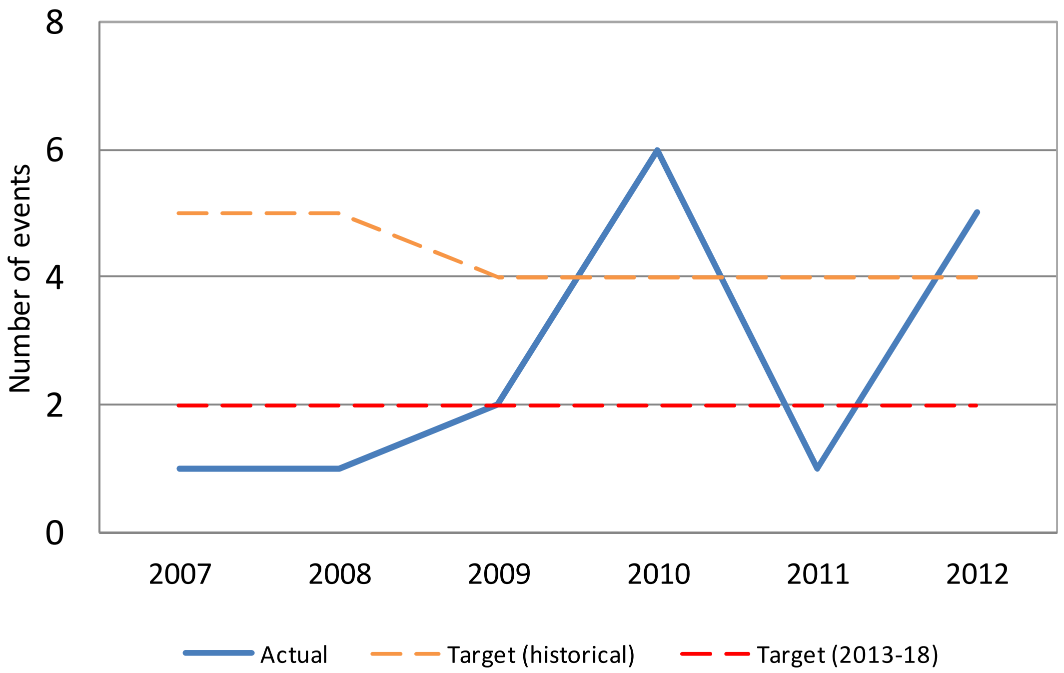
We do not consider an increase in the weighting for 'average outage duration' is necessary to improve and maintain performance because the current weighting appears to have incentivised ElectraNet to improve performance. Given this improvement, ElectraNet will likely continue to improve and maintain performance in the future, particularly if the incidence of low probability, high impact events decreases. An increase in the revenue weighting may therefore result in customers paying more than necessary to incentivise this performance.

We therefore consider that the current weighting of 0.2 per cent for the 'average outage duration' parameter is appropriate and will continue to incentivise the improvement and maintenance of 'average outage duration' performance.

'Loss of supply events > 0.05 system minutes' sub–parameter

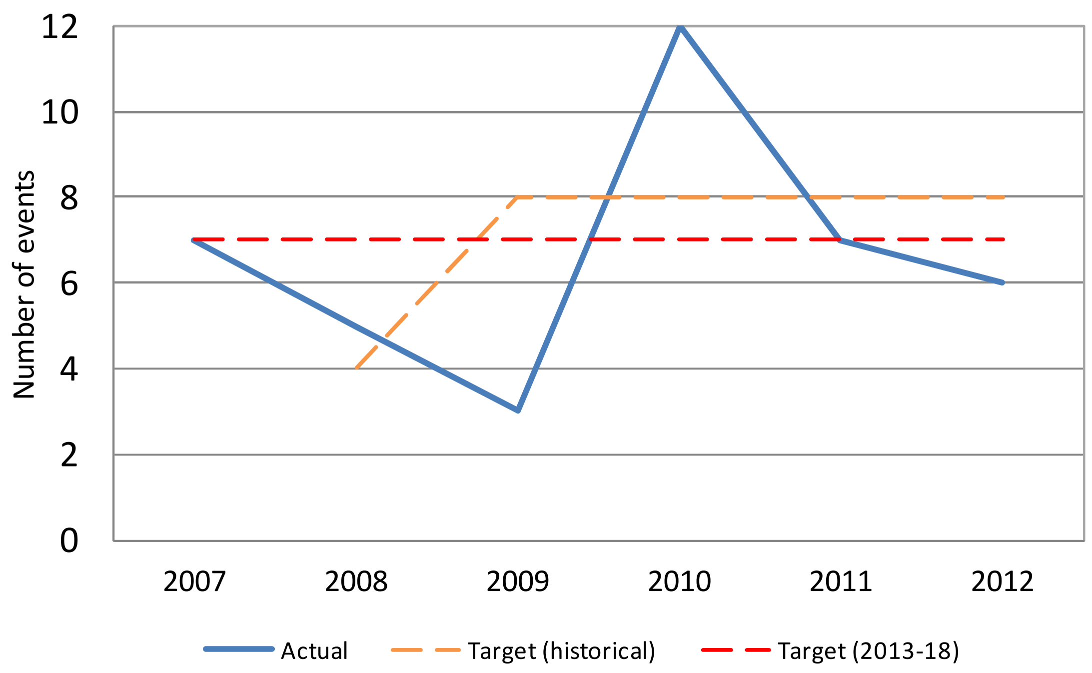
Figure 9.2 and Figure 9.3 illustrate ElectraNet's loss of supply event performance over the past six years.

Figure 9.2 ElectraNet's 'loss of supply events > 0.2 system minutes' performance



Source: ElectraNet, *Email response to EMCa/060, STPIS data reconciliation, ENET232*, 17 August 2012; AER analysis.

Figure 9.3 ElectraNet's 'loss of supply events > 0.05 system minutes' performance



Source: ElectraNet, *Email response to EMCa/060, STPIS data reconciliation, ENET232*, 17 August 2012; AER analysis.

We consider an increased weighting is warranted for the 'loss of supply events > 0.05 system minutes' sub–parameter. While ElectraNet's 'loss of supply events >0.05 system minutes' performance bettered the target in five of the past six years, performance between 2010 and 2012 was poorer than in 2008 and 2009. To help incentivise the improvement and maintenance of performance, we consider a higher weighting for this sub–parameter is appropriate. By contrast, ElectraNet's 'average outage duration' performance does not require a stronger incentive given its marked performance improvement. For this reason, we consider increasing the weighting for 'loss of supply events > 0.05 system minutes' and maintaining the current weighting for 'average outage duration' is appropriate and best meets the objectives of the STPIS.[528]

ElectraNet considered the scope for improvement in loss of supply performance is limited, given the short response times required before penalties are incurred under the loss of supply parameter.[529] However, incentivising shorter response times is not the sole purpose of the loss of supply parameter. It also incentivises efficient asset management and operational practices to reduce the incidence of loss of supply events.[530] By increasing the weighting of the 'loss of supply events > 0.05 system minutes' sub–parameter we are not only trying to incentivise shorter response times but also the development and maintenance of sound asset management and operational practices that help prevent loss of supply events occurring. Given the number of 'loss of supply events > 0.05 system minutes' was higher during 2010–12 than 2008–09, we consider that there may be scope for further improvement in practices to minimise loss of supply events. We also consider it desirable to incentivise the maintenance of sound asset management and operational practices to reduce loss of

528 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme*, March 2011, clause 1.4.

529 ElectraNet, *Revised revenue proposal*, pp. 149–150.

530 AER, *Final decision, Electricity transmission network service providers, Service target performance incentive scheme*, March 2011, p. 7 and 13.

supply events. An increased weighting on the 'loss of supply events > 0.05 system minutes' sub–parameter helps to do this.

EMCa agreed with our position, stating the ‘loss of supply events > 0.05 system minutes’ sub–parameter provides the greatest incentive for correct asset operation and reliability on heavily loaded circuits. EMCa considered that increasing the weight on this sub–parameter incentivises improved performance on radial circuits where failure of correct asset operation can mean long periods of disconnection for remote communities.[531]

The Energy Consumers Coalition of South Australia (ECCSA) supported our view. It stated that parameter weightings should reflect the value that consumers place on the service provided. It considered our weightings more accurately reflect the interests of consumers than ElectraNet's proposed weightings.[532] We agree that parameter weightings should reflect the value that customers place on the parameter. We noted this principle in the recent review of the STPIS.[533] We consider that 'loss of supply events > 0.05 system minutes' is an important sub–parameter for customers, particularly for generators, so should therefore be given an increased weighting. We also reiterate our draft decision that stated each loss of supply sub–parameter incentivises desirable behaviour that customers value. As such, given the 'x' and 'y' thresholds are set appropriately, the two loss of supply sub–parameters should have the same weighting.

Our draft decision is consistent with the new STPIS, released in December 2012.[534] The new STPIS places a heavier weighting on loss of supply events than on average outage duration, at 0.3 per cent and 0.2 per cent respectively. Additionally, the new STPIS places an equal weighting on the two ‘loss of supply’ sub–parameters of 0.15 per cent.[535] We consider similar principles relating to the revenue weightings, where possible, should be applied to ElectraNet for the 2013–18 regulatory control period. Consistent with the new STPIS, the 'loss of supply' sub–parameters have a higher weighting overall than that of the 'average outage duration' parameter. Also, the 'two loss of supply' sub–parameters have an equal weighting of 0.2 per cent each.

Adjustments to reliability targets for proposed capital works

ElectraNet accepted our draft decision on its proposed adjustments to reliability targets for capital works. However, the ESSCA considered we erred in not adjusting ElectraNet's performance targets upwards given we approved a lower capex forecast than the actual capex incurred during the 2008–13 regulatory control period.[536] However, an upward adjustment to ElectraNet's availability targets is not reasonable because the targets are already set at a high level. The STPIS needs to provide reasonably attainable targets to incentivise the improvement and maintenance of service performance. Any upwards adjustments to ElectraNet's availability targets for changes in capex volumes could unfairly penalise ElectraNet while encouraging inefficient investment in reliability. As such, we consider an upwards adjustment to ElectraNet's availability targets is inappropriate.

531 EMCa, *Technical review – revised revenue proposal*, April 2013, pp. 87–88, paragraphs 355–356.

532 ECCSA, *SA Electricity transmission revenue reset, ElectraNet SA application: a response*, February 2013, p. 35.

533 AER, *Explanatory statement, Electricity transmission network service providers, Draft service target performance incentive scheme*, September 2012, pp. 49–50.

534 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme*, December 2012.

535 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme*, December 2012, p. 9.

536 ECCSA, *SA Electricity transmission revenue reset, ElectraNet SA application: a response*, February 2013, p. 35.

9.4.2 Market impact component

ElectraNet accepted our market impact component target of 1585 dispatch intervals.[537] However, the Energy Users Association of Australia (EUAA) submitted that the market impact component ignores the volume of electricity 'redispatched' that might result from market constraints. It considered this creates a risk that ElectraNet will charge consumers more than the economic cost of the constraint.[538] While appreciating no scope exists to amend the scheme, the EUAA suggested we either reduce the revenue weighting from 2 per cent to 0.2 per cent or set a tougher target.[539]

Because no scope exists to review the scheme during the transmission determination we maintain our draft decision on ElectraNet's market impact component. The appropriate avenue to amend the STPIS is through the separate STPIS review process. We recently reviewed the STPIS which concluded with the publication of a new STPIS in December 2012.[540] In the review, we amended the method of calculating targets and actual performance under the market impact component. These amendments incentivise more consistent performance against the market impact component by TNSPs over time.

9.5 AER decision

Decision 9.1: The AER does not accept ElectraNet's revised revenue proposal weightings for the 'loss of supply events > 0.05 system minutes' sub–parameter and the 'average outage duration' parameter. Table 9.1 and Table 9.2 show the AER's final decision on the service component parameter and market impact component parameter values and weightings that will apply to ElectraNet during the 2013–18 regulatory control period.

537 ElectraNet, *Revised revenue proposal*, p. 149.
538 EUAA, *Submission to the AER on ElectraNet revenue draft determination 2013–14 to 2017–18*, February 2013, p. 25.
539 EUAA, *Submission to the AER on ElectraNet revenue draft determination 2013–14 to 2017–18*, February 2013, p. 25.
540 AER, *Final – Electricity transmission network service providers, Service target performance incentive scheme*, December 2012.

10 Efficiency benefit scharing scheme

The efficiency benefit sharing scheme (EBSS) operates in conjunction with the ex ante incentive framework, to provide transmission network service providers (TNSPs) a continuous incentive to reduce operating expenditure (opex). It provides this continuous incentive by allowing a TNSP to retain efficiency gains for five years before passing them on to consumers. It also removes the incentive to overspend in the opex base year to receive a higher opex allowance in the following regulatory control period.

The National Electricity Rules (NER) require the Australian Energy Regulator (AER) to decide:[541]

- the carryover amounts that arise from applying the EBSS during the 2008–13 regulatory control period
- how the EBSS will apply to ElectraNet in the 2013–18 regulatory control period.

The EBSS that applied to ElectraNet during the 2008–13 regulatory control period was the 'first proposed EBSS'.[542] The EBSS that will apply to ElectraNet for the 2013–18 regulatory control period is version one of the EBSS for electricity TNSPs.[543]

10.1 Final decision

We are not satisfied ElectraNet's revised proposed EBSS carryover of –$0.8 million, from the application of the EBSS during the 2008–13 regulatory control period, complies with the scheme requirements. Our reason is that ElectraNet did not adjust the target and actual opex used to calculate the efficiency gains, to account for movements in provisions. We consider a carryover of –$1.8 million complies with the scheme requirements.

When we calculate the carryover amounts for the 2013–18 regulatory control period:

- we will not adjust forecast opex for changes in demand over the 2013–18 regulatory control period because ElectraNet's opex forecasts are not directly related to demand growth
- we will exclude the following cost categories:
    - debt raising costs
    - network support costs
    - self insurance costs
    - land tax
    - additional regulatory reset costs
    - superannuation defined benefits contributions.

We will also adjust actual opex for the 2013–18 regulatory control period to reverse any movements in provisions. This is consistent with the approach we used to forecast opex for the period.

[541] NER, clauses 6A.4.2(a)(6) and 6A.14.1(1)(iv).
[542] 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, but not for subsequent determinations: NER, clauses 11.6.17 and 11.6.18.
[543] AER, *Electricity transmission network service providers efficiency benefit sharing scheme*, September 2007.

Table 10.1 shows the total opex forecasts we will use to calculate efficiency gains and losses for the 2013–18 regulatory control period, subject to adjustments required by the EBSS.

Table 10.1 AER's final decision on ElectraNet's forecast opex for EBSS purposes ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
Total forecast opex	78.8	81.8	83.3	86.7	87.3	417.9
Debt raising costs	–1.1	–1.2	–1.2	–1.2	–1.3	–6.0
Network support	–8.1	–8.2	–8.2	–8.5	–8.6	–41.6
Self insurance	–1.3	–1.3	–1.4	–1.4	–1.4	–6.8
Additional reset costs	0	0	0	–1.5	–1.5	–2.9
Land tax	–2.1	–2.2	–2.3	–2.5	–2.7	–11.8
Superannuation contributions	–1.8	–1.6	–1.4	–1.4	–1.0	–7.2
Forecast opex for EBSS purposes	**64.4**	**67.3**	**68.8**	**70.2**	**70.9**	**341.5**

10.2 ElectraNet's revised proposal

ElectraNet's revised proposal for the application of the EBSS in the 2008–13 regulatory control period incorporated most of our draft decision, except our decision to adjust target and actual opex to account for any movements in provisions. ElectraNet stated provisions properly constitute efficient base year expenditure for liabilities incurred, and form part of the controllable historical and forecast opex.[544]

Similarly, ElectraNet incorporated most aspects of our draft decision in its proposed application of the EBSS to the 2013–18 regulatory control period. However, it did not accept our decision to adjust actual opex for the 2013–18 regulatory control period to reverse any movements in provisions.[545]

10.3 Assessment approach

We did not change our assessment approach for the EBSS from our draft decision. Section 12.3 of our draft decision details that approach.[546]

10.4 Reasons for final decision

This section explains our final decision to adjust forecast and actual opex in the 2008–13 regulatory control period, and actual opex in the 2013–18 regulatory control period, to reverse any movements in provisions. It also explains how we applied, or will apply, the EBSS to both periods.

Movements in provisions

We recognise employee entitlements are appropriately recorded in a provisions account as they are accrued, consistent with standard accounting practice. However, we consider that a provision should

[544] ElectraNet, *Revised revenue proposal*, pp. 104, 156 and 159.
[545] ElectraNet, *Revised revenue proposal*, p. 159.
[546] AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 228.

be distinguished from other liabilities because the timing and amount of the future expenditure required in settlement are uncertain. For example, a liability for an employee entitlement such as annual leave, long service leave or superannuation is accrued some time (even a long time) before it is paid. There can also be some uncertainty as to whether particular expense provisions will materialise in the future. Due to these uncertainties, for forecasting opex purposes, it is more appropriate to consider such costs as they are incurred, not as they accrue.

For these reasons, we consider provisions accrued in a given year do not represent actual costs incurred in that year and should be removed from base year expenditure. However we recognise cash paid out for the expenses to which the provisions relate. This is achieved by reversing the movements in provisions in the base year.[547] The approach we used to forecast ElectraNet's opex for 2013–18 in the final decision is consistent with our approach in our draft decision and our usual approach. The treatment of movements in provisions is discussed more fully in section 3.4.1.

10.4.1 Application of the EBSS in the 2008–13 regulatory control period

We are not satisfied ElectraNet's revised carryover penalty from the application of the EBSS to the 2008–13 regulatory control period complies with the scheme because the calculation does not incorporate our decision regarding movements in provisions.

Our draft decision was to exclude movements in provisions from forecast and actual opex for the EBSS carryover calculation for the 2008–13 regulatory control period. For the EBSS to appropriately reward TNSPs for efficiency gains or penalise them for efficiency losses, we need to apply a consistent approach to opex across regulatory control periods.[548] Because we reverse movements in provisions from ElectraNet's opex forecast for the 2013–18 regulatory control period we need to apply the same approach to movements in provisions when we apply the EBSS to the 2008–13 regulatory control period. ElectraNet did not provide any new information to change our draft decision.

ElectraNet provided us with more accurate information for our calculations if we maintained our draft decision to reverse the movements in provisions. The information related to: [549]

- adjustment for superannuation provision movements from 2005–06
- the apportionment of employee leave provisions to opex
- land tax adjustments.

In our base year calculation of the EBSS target for the 2008–13 regulatory control period we attributed the whole of the superannuation provisions movement for the year to 30 June 2006 ($5.2 million) to opex in our draft decision. However, ElectraNet noted only one third of this amount was correctly attributable to expenditure, while the balance reflected a change in the accounting treatment, which was required to conform to the requirements of the then new Australian International Financial Reporting Standards (AIFRS). We amended our calculations accordingly. ElectraNet also provided a more accurate apportionment of employee leave provisions to opex (58.3 per cent, rather than 57 per cent) and actual land tax payments, which we incorporated in this final decision.

547 Movements in provisions reflect accrued liabilities to provisions less actual cash payments for employee entitlements. Therefore, reversing movements in provisions has the effect of subtracting accrued liabilities and adding cash payments for employee entitlements.
548 This is due to how the scheme works in practice.
549 ElectraNet, *Revised revenue proposal*, pp. 156–7.

Revised carryover amount

When we reverse movements in provisions in forecast and actual opex for 2008–13, and incorporate the data provided by ElectraNet, we calculate a total carryover amount of –$1.8 million. Table 8.1 outlines the carryover amounts that we will include as building blocks to determine ElectraNet's annual revenue requirement.[550]

Table 10.2 AER's final decision on EBSS carryover amounts for 2008–13 regulatory control period ($ million, 2012–13)

	2013–14	2014–15	2015–16	2016–17	2017–18	Total
ElectraNet's revised revenue proposal	–0.6	–2.4	–1.7	0.0	3.9	–0.8
AER's final decision	–1.3	–3.4	–1.3	0.0	4.3	–1.8

Source: ElectraNet, *Revised revenue proposal*, p. 158; AER analysis.
Note: Our final decision was able to incorporate actual rather than estimated data for 2010–11.[551]

10.4.2 Application of the EBSS in the 2013–18 regulatory control period

The Final EBSS will apply to ElectraNet for the first time in the 2013–18 regulatory control period. ElectraNet incorporated most aspects of the AER's draft decision; however, it did not accept our decision to reverse movements in provisions in actual opex.

Movements in provisions

To calculate efficiency gains, the EBSS compares actual opex with forecast opex. To compare like with like, the scheme requires us to measure actual and forecast opex using the same cost categories and the same method.[552] This requirement is relevant to our treatment of movements in provisions. We reversed movements in provisions in ElectraNet's base year expenditure to determine ElectraNet's forecast opex for 2013–18. Therefore, we will reverse any movements in provisions in ElectraNet's actual opex when we calculate the EBSS carryovers for the period.

Superannuation defined benefits contributions

Our draft decision did not accept ElectraNet’s proposed step change to cover the shortfall in the TNSP's superannuation defined benefits plan. However, in light of additional material provided by ElectraNet, our final decision accepts the superannuation shortfall contribution as a step change (section 3.4.2). For EBSS purposes, we will exclude superannuation defined benefits contributions (including the shortfall) from forecast and actual opex for the 2013–18 regulatory control period because the contributions are not forecast using historical expenditure in an efficient base year. ElectraNet agreed that excluding the superannuation defined benefits contributions from the EBSS is consistent with the scheme's intent.[553]

Excluded cost categories

We will exclude the following cost categories from forecast and actual operating expenditure for the 2013–18 regulatory control period because they are not forecast using historical expenditure in an efficient base year:

550 NER, clause 6A.5.4(a)(5).
551 ElectraNet, *Annual regulatory financial report 1 July 2011 to 30 June 2012*, October 2012, p. 31.
552 AER, *Final electricity transmission network service providers efficiency benefit sharing scheme*, September 2007, p. 7.
553 ElectraNet, *Response to AER information request AER RP 009 defined benefits superannuation*, 22 February 2013.

- debt raising costs
- network support costs
- self-insurance costs
- land tax
- additional regulatory reset costs
- superannuation defined benefits contributions.

We will also adjust actual opex for the 2013–18 regulatory control period to reverse any movements in provisions. This is consistent with the approach we used to forecast opex for the period.

Efficiency gains in 2013–14

For the purpose of calculating efficiency gains, and to provide ElectraNet with a continuous incentive to reduce opex, we will treat 2013–14 as year six of the EBSS, not as year one of the final EBSS.[554] Because we are finalising this determination before the completion of 2012–13, to calculate the efficiency gains or losses for that year we need to use an estimate for 'actual' opex.[555] Where differences arise between this estimate and the actual expenditure of 2012–13, this difference will be accounted for when we calculate the efficiency gain for 2013–14.

The efficiency gain in 2013–14 (year 6) will be calculated as follows:

$$E_6 = (F_6 – A_6) – (F_5 – A_5) + (F_3 – A_3)$$

where F_6 is the forecast operating expenditure we approved for year 6, and A_6 is the actual operating expenditure incurred for year 6, and so on.[556] The formula references year 3 because it is the base year used to forecast opex.

554 This is consistent with the EBSS considerations in the NER, clause 6A.6.5(b).

555 This is discussed more fully in our draft decision; AER, *Draft decision: ElectraNet transmission determination, November 2012*, pp. 231–2.

556 AER, *Final electricity transmission network service providers efficiency benefit sharing scheme*, September 2007, p. 6. We have amended the formula in the guidelines to reflect the fact that the base year used to forecast opex is year 3 not year 4. We have done this to be consistent with the NER requirements in clause 6A.6.5(b) which requires us to have regard to certain factors when we implement the EBSS.

10.5 Decision

Decision 10.1: Table 8.1 sets out the EBSS carryover amounts included as building blocks in the determination of ElectraNet's annual revenue requirement.

Decision 10.2: When we calculate the carryover amounts for the 2013–18 regulatory control period we will not adjust forecast opex for changes in demand and we will exclude the following cost categories:

- debt raising costs
- network support costs
- self insurance costs
- land tax
- additional regulatory reset costs
- superannuation defined benefits contributions.

We will also adjust actual opex for the 2013–18 regulatory control period to reverse any movements in provisions.

Decision 10.3: Table 10.2 shows the forecast opex that we will use to calculate efficiency gains and losses in the 2013–18 regulatory control period.

11 Contingent projects

This attachment sets out our final decision on ElectraNet's proposed contingent projects and the associated trigger events.

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'.[557] The occurrence of the trigger event must be probable.[558] However, the event or the costs associated with the event must be uncertain.[559]

If a trigger event occurs during the 2013–18 regulatory control period, we will assess the contingent project's costs on application by ElectraNet under clause 6A.8.2 of the NER. If we approve the contingent project's costs at that time, we will amend ElectraNet's determination to account for the increased costs associated with the contingent project.

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.[560] For this reason, the trigger event must be adequately defined and the proposed contingent capex must reasonably reflect the capex criteria under the NER.[561]

11.1 Final decision

We do not accept ElectraNet's contingent project proposal:

- we do not accept the 'Northern Suburbs reinforcement' project as a contingent project because the trigger event is not probable during the 2013–18 regulatory control period.[562]

- we have modified the trigger events for nine proposed contingent projects. We consider the projects are appropriate to be considered contingent projects, but we are not satisfied that the proposed trigger events satisfies the requirements for trigger events. After modifying the trigger events for these projects we accept these as contingent projects.

- we accept ElectraNet's two other proposed contingent projects as presented because they satisfy the requirements of the NER.

Table 11.1 sets out the AER's final decision on ElectraNet's proposed contingent projects including the underlying drivers of the projects.

557 NER, clause 6A.8.1(c)(5).
558 NER, clause 6A.8.1(c)(5).
559 NER, clause 6A.8.1(c)(5)(i).
560 NER, clauses 6A.8.1(c)(4); 6A.8.2.
561 NER, clause 6A.8.1(b)(2)(ii).
562 NER, clause 6A.8.1(c)(5).

Table 11.1 AER final decision on ElectraNet's proposed contingent projects

RRP No.	Project	Underlying driver	Accept, reject or accept with modified trigger	Cost ($million)
8	Northern Suburbs reinforcement	Additional residential, commercial and industrial development	Reject	50
1	Lower Eyre Peninsula reinforcement	New mining load	Accept with modified trigger	340
11	Upper North Region line reinforcement	New mining load	Accept with modified trigger	60
4	Yorke Peninsula reinforcement	New mining load	Accept with modified trigger	190
12	East Terrace transformer	Railway electrification, hospital refurbishment	Accept with modified trigger	23
10	Port Pirie system reinforcement	Expansion of the Nystar lead smelter	Accept with modified trigger	52
9	Mid North connection point	New mining load	Accept with modified trigger	60
7	Upper South East Network Augmentation	Constraints in the network; or generator connection	Accept with modified trigger	50
2	Riverland reinforcement	Insufficient available dispatch into South Australia to provide support to the Riverland	Accept with modified trigger	400
3	Fleurieu Peninsula reinforcement	Failure of non-network solution	Accept with modified trigger	210
5	South East to Heywood Interconnection Upgrade	Network limitations and constraints	Accept	63
6	Davenport reactive support	Temporary or permanent closure of Playford and Northern Power Stations during the South Australian summer period	Accept	42
Total				**1540**

Source: ElectraNet, *Revised revenue proposal*, pp. 167–179; ElectraNet, *Revised revenue proposal*, appendix M; AER analysis.

11.2 ElectraNet's revised proposal

ElectraNet's revised revenue proposal included twelve proposed contingent projects with a combined value of $1540 million ($nominal).[563] This is nine projects less, or $1007 million less of contingent capex than that included in ElectraNet's revenue proposal.

We note our draft decision did not accept any of ElectraNet's 21 proposed contingent projects included in its initial revenue proposal.

[563] All proposed contingent capex is in nominal dollars.

11.3 Assessment approach

We reviewed each of ElectraNet's revised proposed contingent projects in the context of the NER requirements.[564] We considered whether:

- the proposed contingent project is reasonably required to achieve any of the capex objectives[565]
- the proposed contingent project expenditure is not otherwise provided for in the capex proposal.[566]
- the proposed contingent project reasonably reflects the capex criteria,[567] and exceeds the defined threshold[568]
- the trigger events are appropriate. This included assessing whether the trigger event:
  - is reasonably specific[569]
  - makes the project reasonably necessary to achieve the capex objectives[570]
  - is all that is required for the revenue determination to be amended[571]
- the occurrence of the trigger event is probable during the 2013–18 regulatory control period.[572]

11.4 Reasons for final decision

For the final decision, we have grouped the proposed contingent projects into two categories:

- Load driven proposed contingent projects—this category includes seven proposed contingent projects which we identified are driven by a demand increase at particular points on the ElectraNet network. Due to their similarity these projects are considered together.
- Non-load driven proposed contingent projects—this category includes five proposed contingent projects which we identified are not driven by demand increases but rather are driven by other events. Because these projects' trigger events vary considerably we considered them individually.

11.4.1 Load driven proposed contingent projects

We do not accept all of ElectraNet's load driven proposed contingent projects. Specifically, we do not accept the 'Northern Suburbs reinforcement' project as a contingent project because the trigger event is not probable during the 2013–18 regulatory control period.[573]

However, we do accept ElectraNet's six other load driven proposed contingent projects:

- Upper North Region line reinforcement
- Lower Eyre Peninsula reinforcement

564 NER, clause 6A.8.1.
565 NER, clause 6A.8.1(b)(1).
566 NER, clause 6A.8.1(b)(2)(i); NER, clause 6A.6.7(a)(1).
567 NER, clause 6A.8.1(b)(2)(ii).
568 NER, clause 6A.8.1(b)(2)(iii).
569 NER, clause 6A.8.1(c)(1).
570 NER, clause 6A.8.1(c)(2).
571 NER, clauses 6A.8.1(c)(4); 6A.8.2.
572 NER, clause 6A.8.1(c)(5).
573 NER, clause 6A.8.1(c)(5).

- Yorke Peninsula reinforcement
- East Terrace transformer
- Mid North connection point
- Port Pirie system reinforcement.

In our draft decision, we did not accept any of the load driven proposed contingent projects.[574] We considered:

- The expansion of BHP Billiton's Olympic Dam mine projects had been indefinitely deferred.
- Some projects would be triggered by a demand increase consistent within ElectraNet's demand forecast for the 2013–18 regulatory control period. Therefore these projects should be considered ex ante capex rather than contingent projects. We noted that the NER requires that ElectraNet's ex ante capex forecast is sufficient to meet expected demand for the 2013–18 regulatory control period.
- Some projects that would be triggered by a demand increase above ElectraNet's demand forecast should not be accepted because:
  - ElectraNet was not able to identify the underlying driver that would make the trigger event probable
  - the trigger events were not consistent with the NER.

ElectraNet's revised revenue proposal did not include the proposed contingent projects associated with the now deferred expansion of BHP's Olympic Dam mine. ElectraNet also included a considerably lower demand forecast than the one in its initial revenue proposal. Accordingly, ElectraNet reduced the number of demand driven contingent projects based on its revised 2013–18 demand forecast and removed those which it considered are now less likely to occur:

> ElectraNet has reviewed its proposed contingent projects in light of the 10 per cent probability of exceedance demand forecasts on which the load driven capital expenditure program of the revised Revenue Proposal is based.
>
> Adoption of the 10 per cent probability of exceedance demand forecasts has deferred the driver date for all load driven contingent projects to beyond the 2013-2018 regulatory control period (other than those driven by a step change in load).[575]

We accept that as a result of ElectraNet adopting a lower demand forecast, none of its revised proposed contingent projects are forecast to occur within the demand forecast for the 2013–18 regulatory control period. Rather all revised demand driven contingent projects require a step change in demand. Further, projects that were above the 2013–18 demand forecast that ElectraNet used for its revenue proposal are now further above the demand forecast and less likely to occur

The framework for contingent projects only allows us to include proposed contingent projects in our final decision in a narrow range of situations. In particular, the trigger event for the proposed contingent projects must :

[574] AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 237.

- not be 'sufficiently certain' that it will occur during the regulatory control period to allow it to be included in the ex ante capex allowance[576]
- be 'probable' during the regulatory control period.[577]

ElectraNet's revised proposed load driven contingent projects will only occur during the 2013–18 regulatory control period if an event causing a step change in demand occurs. In the absence of this event, these projects will not occur during the 2013–18 regulatory control period. We therefore consider that the occurrence of the trigger event is not sufficiently certain to include them in the ex ante capex allowance. Each of these proposed load driven contingent projects would therefore satisfy the first element, above.

To be included as a contingent project, ElectraNet must also demonstrate that these projects could still be said to be probable. Our draft decision stated that we did not accept ElectraNet's proposed contingent projects that were above the demand forecast because 'ElectraNet did not explain why the demand increase is likely to occur'.[578]

> 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.[579]

In considering whether the proposed contingent projects included in the revised revenue proposal are probable we have considered whether the underlying driver of these projects was identifiable, specific and are reasonably expected to occur. In respect of all projects, other than the Northern Suburbs, we were satisfied that ElectraNet has identified a specific underlying driver which would make the trigger event probable.

We do not accept the Northern Suburbs reinforcement project because we considered that the underlying driver of this project is organic load growth. Under the organic load growth forecast, this project is not forecast to be required until 2021. ElectraNet stated,

> Network load flow studies show that with additional residential, commercial and industrial development in the outer northern suburbs of Adelaide and around the townships of Roseworthy and Gawler, major expansion of the 66 kV distribution sub-transmission network is required along with the establishment of a new transmission connection point to supply this load.[580]

ElectraNet referred generally to additional residential, commercial and industrial development, as driving this project. We consider that all of these items are organic load growth which are captured under the demand forecast. As we noted in our draft decision, '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'.[581] We could not identify a specific event which would result in a step change in demand which would require this project to be undertaken before 2021. In the absence of any other driver, we cannot say that the trigger event for this project is probable during the 2013–18 regulatory control period. We therefore do not accept this proposed contingent project.

576 NER, clause 6A.8.1(c)(5)(i).
577 NER, clause 6A.8.1(c)(5).
578 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 246.
579 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 245.
580 ElectraNet, *Revised revenue proposal*, Appendix M, p. 27.
581 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 246.

In respect of the other six proposed contingent projects, we are satisfied that ElectraNet has identified a specific underlying driver which would make the trigger event probable.[582] As noted, we were also satisfied that ElectraNet identified specific underlying drivers that would cause a step change in demand.

Appendix B sets out each of the proposed contingent projects that we accept and the trigger events.

Consultation on the Northern Suburbs reinforcement project

We consulted and engaged with ElectraNet regarding its proposed contingent projects on numerous occasions for the purpose of our draft decision and also our final decision, see appendix C. This consultation also included discussions regarding the Northern Suburbs reinforcement project.

We sought written advice from ElectraNet about the Northern Suburbs reinforcement project. On 19 February 2013, in relation to this project, EMCa asked ElectraNet to identify the step change in load.[583] ElectraNet's response referred to increased load growth as driving the need for this project.[584]

Further, on 21 and 26 February 2013, we discussed specific concerns with ElectraNet regarding the Northern suburbs reinforcement project. At these meetings we provided feedback to clarify our intent. That is, ElectraNet must demonstrate a step load increase that makes this project probable.

ElectraNet provided a response to this 'verbal feedback from the AER that insufficient information has been provided on the status and likelihood of the Northern suburbs load developments occurring'.[585] ElectraNet provided additional information about dwelling developments.[586] However, ElectraNet's response did not provide a specific step load. Rather, it confirmed that ElectraNet's proposal for this project is based on organic load growth.

11.4.2 Non-load driven proposed contingent projects

We accept all five non-load driven proposed contingent projects included in ElectraNet's revised revenue proposal. Our considerations and reasons are set out below.

South East to Heywood interconnection upgrade

We accept this proposed contingent project in our final decision. We were satisfied in our draft decision with the need for this proposed contingent project but were not satisfied with the trigger event as proposed.[587] ElectraNet's revised revenue proposal amended the trigger event to be consistent with the indicative trigger event set out in our draft decision.

Upper South East network augmentation

We accept this proposed contingent project in our final decision. In our draft decision, we were not satisfied that the contingent project was reasonably required or that the trigger event was specific, or

582 NER, clause 6A.8.1(c)(1).
583 EMCa, Request EMCa068, 19 February 2013.
584 ElectraNet, ENET347, p. 5 [Confidential].
585 ElectraNet, ENET 365, p. 2, ElectraNet noted that it was providing further information in relation to these verbal discussions with the AER.
586 ElectraNet, ENET 365, pp.2–3 [Confidential].
587 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 251.

probable.[588] In relation to this project and the other market benefits projects, our draft decision considered:

> 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.[589]

ElectraNet provided additional information about the proposed generation and the likely connection load.[590] Should this generation come on line then this project will go ahead. We are therefore satisfied that this is an appropriate trigger event and accept this proposed contingent project.

ElectraNet's revised revenue proposal also proposed that publication by AEMO of evidence of material constraints in the upper south east of ElectraNet's network would prompt ElectraNet to consider market benefits in addressing this issue. We are satisfied that the constraint is an appropriate trigger event and therefore accept this proposed contingent project.

We consider that both of these drivers would be appropriate trigger events for the Upper South East project to go ahead. The occurrence of either of the trigger events would make the project reasonably required. The analysis undertaken by ElectraNet demonstrates that these trigger events are probable during the 2013–18 regulatory control period.

Riverland reinforcement

In respect of the trigger event related to the decrease in available dispatch, ElectraNet amended the trigger event to be consistent with the indicative trigger event set out in our draft decision. We have further modified the trigger event to make it specific[591] by including a reference to the level that dispatch will need to reduce to, in order to trigger this project. After making this modification, we accept this proposed contingent project in our final decision.

We were satisfied in our draft decision that this proposed contingent project was required but were not satisfied with the trigger event as proposed.[592] ElectraNet's revised revenue proposal modified this proposed contingent project. It removed the trigger event which was linked to an increase in demand. ElectraNet considered that this demand increase was no longer probable.[593]

Davenport reactive support

We accept this proposed contingent project in our final decision. In our draft decision we were satisfied that this proposed contingent project was required but we were not satisfied with the trigger event ElectraNet proposed.[594] ElectraNet's revised revenue proposal amended the trigger event to be consistent with the indicative trigger event set out in our draft decision.[595]

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588 AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 249.
589 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 248.
590 ElectraNet, *Contingent projects,* ENET347, p. 4 [Confidential].
591 NER, clause 6A.8.1(c).
592 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 250.
593 ElectraNet, *Revised revenue proposal*, p.175.
594 AER, *Draft decision: ElectraNet transmission determination, November 2012*, p. 249.
595 ElectraNet, *Revised revenue proposal*, p.178.

Fleurieu Peninsula reinforcement

We accept this proposed contingent project in our final decision. In our draft decision we were not satisfied that this should be included as a contingent project. In ElectraNet's revenue proposal, it stated that this project was triggered by a connection point request.

Connection point requests are ultimately driven by demand increases. Our analysis for our draft decision indicated that the demand increase required to trigger the project was forecast to occur (under ElectraNet's revenue proposal forecast) within the 2013–18 regulatory control period.

ElectraNet advised that the distribution network in the Fleurieu Peninsula is suffering limitations:

> Following the expected implementation of a non-network solution followed by a distribution solution, the capacity of the distribution system following the deployment of these solutions is expected to be exceeded by around 2025. Any unexpected demand increase above the current demand forecasts and/or failure of the non-network solution as a technically and economically viable option will advance the need for this development, potentially to within the next regulatory control period.[596]

While ElectraNet's proposed trigger event refers to demand growth, we have found that the proposed contingent project is not driven by the demand increase. Rather, this project will only be required if the non-network solution fails. We consider that this is the real driver of the project, which if it occurred would mean that the project is reasonably required.

We therefore consider that this would be an appropriate trigger event for the Fleurieu Peninsula reinforcement project. While there is uncertainty around this trigger event, the occurrence of the trigger event would make the project reasonably required. The analysis undertaken by ElectraNet, which we accept, demonstrates that this trigger event could be said to be probable during the 2013–18 regulatory control period.

11.5 AER decision

Decision 11.1: The AER accepts eleven of the twelve proposed contingent projects. Project details and trigger events are set out in appendix B.

596 ElectraNet, Revised revenue proposal, Appendix M, p. 12.

12 Pricing methodology and negotiated services

The Australian Energy Regulator (AER) must approve a pricing methodology. This establishes a tariff structure and describes how a transmission network service provider (TNSP) allocates its revenues to its prescribed transmission services and connection points.[597] A pricing methodology does not, however, apply to a TNSP's negotiated services. Their terms and conditions are negotiated between a TNSP and a service applicant, or alternatively through arbitration and dispute resolution by a commercial arbitrator. To facilitate these processes the National Electricity Rules (NER) requires the AER to approve a negotiating framework and determine a TNSP's negotiated transmission service criteria (NTSC).

12.1 Final decision

We maintain our draft decision approving ElectraNet's proposed pricing methodology. ElectraNet's proposed negotiating framework is approved because, following its incorporation of our suggested revisions,[598] it meets the requirements in the NER.[599] We affirm that the NTSC specified in our draft decision (reproduced at section12.5) reflect the negotiating service principles[600] and will take effect at the commencement of the 2013–18 regulatory control period.

12.2 ElectraNet's revised proposal

ElectraNet did not propose amendments to the pricing methodology approved in our draft decision or comment on the NTSC we published (reproduced at section 12.5). It did revise its negotiating framework but only to address the revisions required by our draft decision.

12.3 Assessment approach

We considered ElectraNet's proposed negotiating framework and pricing methodology using the assessment approach outlined in our draft decision.[601] No submissions from interested stakeholders were received on matters relating to ElectraNet's pricing methodology or negotiated services.

12.4 Reasons for final decision

Our draft decision determined that paragraph 6.1.3 of ElectraNet’s proposed negotiating framework did not reflect the NER since it combined two separate obligations relating to the cost of a negotiated service into one complex sentence.[602] In response ElectraNet incorporated our suggested revision making paragraph 6.1.3 two sentences instead of one. This increases the clarity of ElectraNet's proposed negotiating framework and better reflects the requirements of the NER.[603]

Paragraph 7.2 of the proposed negotiating framework originally contained a citation error. This could have caused confusion but it has been corrected and thus addressed. Revisions to paragraph 9.1.1 were also suggested in our draft decision. That paragraph was intended to reflect the NER requirement that a negotiating framework state that *each party* use its reasonable endeavours to progress and finalise negotiations within agreed time periods.[604] We consider the reference to 'each party' in the NER is intended to create a symmetrical obligation on both a service applicant and a

[597] NER, clause 6A.24.1(b)(1) and (2).
[598] AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 267.
[599] NER, clause 6A.9.5(c).
[600] NER, clause 6A.9.1.
[601] AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 262.
[602] AER, *Draft decision: ElectraNet transmission determination,* November 2012, p. 262-3.
[603] NER, clause 6A.9.5(c)(i) and (ii).
[604] NER, clause 6A.9.5(c)(5).

transmission network service provider (TNSP). However, in our draft decision we noted that such an obligation was only placed on a service applicant, not ElectraNet. This has been addressed through the insertion of an additional paragraph in ElectraNet's negotiating framework which now places an obligation on both a service applicant and ElectraNet to use their reasonable to finalise negotiations.[605]

12.5 Negotiated transmission service criteria

This section reproduces the NTSC specified in our draft decision. In accordance with our final decision, it is the NTSC that will apply to ElectraNet for the 2013–18 regulatory control period.

12.5.1 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.

12.5.2 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

605 ElectraNet, *Revised negotiating framework for 1 July 2013 to 30 June 2018*, January 2013, paragraph 9.1.1(a)-(b).

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 5.1a and 5.1 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.

12.5.3 Criteria for access charges

Access charges

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) to (j) of the NER and the costs that are likely to be incurred by a person referred to in clause 5.4A(h).

13 Cost pass throughs

The pass through mechanism of the National Electricity Rules (NER) recognises a transmission network service provider (TNSP) can be exposed to risks beyond its control, which may have a 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 for which the transmission determination does not account.

The NER specifies pass through events that apply to all TNSPs:[606]

- a regulatory change event
- a service standard event
- a tax change event
- an insurance event[607]
- in addition to those above, an event specified in a transmission determination for a regulatory control period.[608]

This section sets out our final decision on the additional pass through events that ElectraNet nominated for the 2013–18 regulatory control period.

13.1 Final decision

The following three nominated pass through events will apply to ElectraNet in the 2013–18 regulatory control period:

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

This section sets out the definitions of the approved nominated pass through events.

Terrorism event

We accept the terrorism event as nominated by ElectraNet in its pass through event proposal.

> A terrorism event is:
>
> 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*.[609]

606 NER, clauses 6A.7.3.

607 An insurance event is different from an insurance cap event. The difference is explained in our draft decision, 16.4.3.

608 In August 2012, the Australian Energy Market Commission (AEMC) made a rule that enables TNSPs to nominate additional pass through events as part of their revenue proposals. Transitional arrangements for ElectraNet are set out in clause 11.49.4 of the NER.

609 ElectraNet's proposed definition is the same as the definition previously included in the NER.

Natural disaster event

We do not accept the natural disaster event nominated by ElectraNet in its revised proposal. We have included an explanation of 'major' in the definition.

A natural disaster event is:

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*.

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean *material* as that term is defined in the Rules (that is, 1 per cent of the TNSP's maximum allowed revenue in that year).

Note:

In assessing a natural disaster event pass through application, 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.

Insurance cap event

We do not accept the insurance cap event nominated by ElectraNet in its revised proposal. We have substituted our own definition:

An insurance cap event means an event whereby:

1. ElectraNet:

   a. makes a claim and receives a payment under a relevant insurance policy, or

   b. would have been entitled to make a claim or receive a payment under a relevant insurance policy but for the application of a relevant policy limit, and

2. ElectraNet incurs costs beyond the relevant policy limit, and those costs would have been recovered under the insurance policy had the limit not been exhausted, and

3. the costs beyond the relevant policy limit *materially* increase the costs to ElectraNet of providing *prescribed transmission services*.

For 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, or would have given, rise to the claim, and

   b. the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the *regulatory control period* in which the insurance policy is issued.

5. 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.

Note:

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.

Additional pass through event

We do not accept the proposed pass through event ElectraNet submitted in its revised proposal.[610] ElectraNet defined the event as an event '*that would be triggered by a decision from ESCOSA that results in a more onerous forecast demand obligation under the ETC*'.[611]

We do not accept the proposed event, because ElectraNet submitted its proposed pass through event after the date permitted by the NER under the transitional arrangements which allowed it to nominate cost pass through events as part of its revenue proposal.[612]

ElectraNet also submitted that we approve an appropriate pass through event of our own accord as part of our final decision. However, we do not propose to nominate a pass through event of our own accord because we are not satisfied that any pass through event nominated by us will meet the NER pass through event considerations, because:

- ElectraNet did not clearly identify the nature or type of event[613]
- the NER already provides pass through events that may allow ElectraNet to recover additional capital costs incurred as a result of a regulatory change event or a service standard event.[614]

13.2 ElectraNet's revised proposal

In its revised proposal, ElectraNet adopted the terrorism event and the natural disaster event set out in our draft decision. However, it did not agree with including the word 'major' in the natural disaster event definition (that is, that the event must be a 'major' fire, flood, earthquake or other natural disaster). It submitted that if the materiality threshold was met (being 1 per cent of the maximum allowed revenue in that year) then the event would clearly be 'major'.

ElectraNet did not agree with the insurance cap event definition set out in our draft decision. It incorporated most aspects of our insurance cap event definition in its revised proposal but modified the triggers for the event. The modifications allow the event to be triggered in circumstances when ElectraNet would be entitled to receive a payment under an insurance policy but for the application of a policy limit. ElectraNet was concerned that limits under some insurance policies may restrict how often it can make a claim, or may impose an aggregate total on claims payable during any one period of insurance.

ElectraNet also modified the definition of the 'relevant policy limit' in the insurance cap event definition so that 'relevant policy limit' can include a policy limit which applied in a previous regulatory control period.

In response to our draft decision ElectraNet also submitted:

610 ElectraNet, *Revised revenue proposal*, p. 36.
611 ESCOSA is the Essential Services Commission of South Australia. The ETC is the South Australian Electricity Transmission Code, TC/07, effective 1 July 2013.
612 NER, clause 11.49.4.
613 NER, Chapter 10, Glossary, *nominated pass through event considerations*, 6A.7.3(a1)(5).
614 Chapter 10, Glossary, nominated pass through event considerations, 6A.7.3(a1)(5).

- the NER does not permit us to specify the matters to which we will have regard in assessing a pass through application, in the definition of the event
- we should specify that italicised terms in the definitions have the same meaning as those defined terms in the NER.

Additional pass though event

ElectraNet proposed an additional nominated cost pass through event in its revised revenue proposal. It defined the event as a more onerous demand forecast obligation under the South Australian ETC.[615] ElectraNet stated it had applied to ESCOSA to amend the ETC definition of forecast agreed maximum demand (FAMD) and ESCOSA's decision on ElectraNet's application may result in a more onerous demand forecast obligation. The more onerous obligation would trigger ElectraNet's proposed nominated cost pass through event.

ElectraNet stated it will incur additional capital costs if the event is triggered, because it will be obliged to comply with its more onerous obligations under the ETC. ElectraNet considered its proposed cost pass through event will allow it to recover any additional costs incurred during the course of the 2013–2018 regulatory control period as a result of complying with a more onerous obligation under the ETC.

ElectraNet proposed that we could include its nominated pass through event in our final decision in one of two ways:

- by accepting an out of time pass through event, effectively waiving the time limitations imposed under the transitional pass through provisions in chapter 11 of the NER
- by proposing our own pass through event.

13.3 Assessment approach

This section discusses our assessment approach to the pass through events ElectaNet nominated in its proposal and the additional event it nominated in its revised proposal.

Nominated pass through events

In considering the pass through events that ElectraNet nominated in its proposal, we had regard to:

- the efficient allocation of risk
- the nominated pass through event considerations in the NER[616]
- advice from AM Actuaries.[617]

Efficient allocation of risk

Our starting point for considering pass through events is the provision of appropriate incentives to promote efficient and prudent risk management. The aim is thus to align the financial risks of providing network services with those best able to manage those risks – namely, the TNSPs. So, a nominated cost pass through mechanism is intended to ensure the efficient funding of risks when it is uneconomical for the service provider to get insurance cover or be paid a self insurance allowance. A

[615] South Australian Electricity Transmission Code, TC/07, 1 July 2013.
[616] NER, definition of '*nominated event pass through considerations'*, chapter 10.
[617] We engaged AM Actuaries to provide advice on: the practical implications of an insurance cap event; cost pass through policy considerations; and ElectraNet's proposed insurance.

pass through event should be approved only when the potential financial damage of the event is so extreme that it is effectively deemed not insurable.[618] The critical issue is the level of damage at which this is expected to occur.

Nominated pass through event considerations

The Australian Energy Market Commission (AEMC), in its Rule Determination, gave TNSPs the ability to nominate cost pass through events.[619] It said:

> For the incentive regime to be maintained, any nominated pass through event should only be accepted when event avoidance, mitigation, commercial insurance and self insurance are unavailable, or the cost pass through is the least inefficient option.[620]

To promote the efficient allocation of risk between service providers and their customers, the AEMC amended the NER to include nominated pass through event factors that we must consider when approving additional pass through events. The considerations are:[621]

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.

We are currently taking steps to review our regulatory approach to nominated pass through events in determinations. Some key issues for us are how to better reflect efficient risk sharing arrangements between service providers and their customers, and how to align risk with the party best able to manage it. We intend to consult more widely on these matters.

Additional pass through event

In deciding whether to accept ElectraNet's proposed additional pass through event, we must consider whether the NER's transitional provisions allow the nominated pass through event to be included in this revenue determination.[622] The AEMC's recent changes to the NER included transitional arrangements for ElectraNet.[623] The transitional arrangements allowed ElectraNet to submit a

618 Insurability in this context relates to available capacity in the market to insure the risk. Typically, affordability is the main consideration.

619 AEMC, *Final rule determination, National electricity amendment (Cost pass through arrangements for network service providers) Rule 2012*, August 2012, p. ii.

620 AEMC, *Draft rule determination, National electricity amendment (Cost pass through arrangements for network service providers) Rule 2012*, May 2012, p.17.

621 NER, chapter 10 definition of '*nominated pass through event considerations'.*

622 NER, clause 11.49.4.

623 NER, clause 6A.6.9.

proposed pass through event for its revenue proposal no later than 30 days after 2 August 2012. If we are satisfied ElectraNet has validly proposed its additional pass through event, we must have regard to the nominated pass through event considerations when assessing the proposed event.[624]

We must also have regard to the nominated pass through event considerations in considering whether to include a pass through event of our own accord under clause 6A.7.3.

13.4 Reasons for final decision

This section sets out our reasons for:

- approving a terrorism event, a natural disaster event and an insurance cap event to apply to ElectraNet in this determination
- amending the natural disaster event and the insurance cap event
- not accepting the proposed additional pass thorugh event that ElectraNet submitted in its revised proposal or proposing an additional pass through event of our own accord.

Terrorism event

We accepted ElectraNet's proposed definition of a terrorism event in our draft decision because it is consistent with the nominated pass through event considerations.[625]

In August 2012, the AEMC rule change removed a terrorism event from the list of pass through events under the NER. 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. The definition ElectraNet proposed, and we approve, is the same as the previous NER definition of a terrorism event.

Natural disaster event

We do not accept the natural disaster event as nominated by ElectraNet in its revised proposal. We have included an explanation of 'major' in the definition.

ElectraNet adopted all of our amendments to its proposed natural disaster event definition, as set out in our draft decision. One of those amendments was to require the natural disaster to be a 'major' fire, flood, earthquake or other natural disaster. However, ElectraNet considered the revision was not necessary because:

- if the materiality threshold defined in the NER (1 per cent of the maximum allowed revenue for that year) is met, then the event is clearly a major event[626]
- the term natural disaster implies a major event.

We disagree with ElectraNet's interpretation of 'major' so we included a definition of 'major' in our final decision. We consulted with ElectraNet about this, and while it still considers it is unnecessary to add the word 'major', it has no substantive objection to our proposed definition.[627]

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624 NER, clause 6A.6.9(b); NER, chapter 10 definition of '*nominated pass through event considerations*'.
625 AER, *Draft decision: ElectraNet transmission determination*, November 2012, pp. 271-272.
626 ElectraNet, *Revised revenue proposal*, p. 177.

Defining the term 'major' in the natural disaster event definition

We consider the term 'major' means an event that is serious or significant: it does not mean 'material' as defined in the NER.[628] That is, a natural event that results in costs to ElectraNet over 1 per cent of its maximum allowed revenue in a year will not necessarily be considered a 'major fire, flood, earthquake or other natural disaster.'

In our draft decision, we determined 1 per cent of ElectraNet's average maximum allowed revenue for 2013–18 is around $3 million per year. We do not consider that costs that arise from a natural event that causes around $3 million dollars should necessarily be passed onto consumers.

The event must be a 'major' natural disaster event, in the sense that it is a serious or significant natural disaster event. Including a definition of the term 'major' in the natural disaster event definition:

- is consistent with the nominated pass through event considerations
- ensures manageable and affordable risk lies with ElectraNet, and not its customers
- provides an incentive for ElectraNet to manage the risk through insurance, self insurance and mitigation.

Nominated pass through event considerations

The NER requires us to assess ElectraNet's proposed natural disaster event having regard to the nominated pass through event considerations which include:[629]

1. whether ElectraNet can insure against the proposed event on reasonable commercial terms[630]
2. whether the proposed event can be self insured.[631]

We consider insurance is likely to be available on reasonable commercial terms for natural disasters that are less than serious or significant:

- Businesses may obtain insurance cover for transmission line loss up to US$20 million. ElectraNet acknowledged insurance is available for damage to transmission and distribution lines, when it cited a report commissioned by Grid Australia.[632] The Grid Australia report indicated commercial insurance for damage to transmission and distribution lines may be available for cover up to, but not above, US$20 million.[633] This insurance ceiling is significantly higher than ElectraNet's materiality threshold of approximately A$3 million.
- In 2010, Powerlink[634], obtained insurance for risks to its towers and lines consistent with the insurance ceiling noted in the Grid Australia report.[635]

Specifying that the natural disaster event must be a serious and significant event helps ensure the event captures only potential financial damage that is not insurable.

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627 ElectraNet, *Email response to information request AER RRP18, Nominated pass through event definitions*, ENET366, 26 March 2013, p. 3.
628 NER, chapter 10, definition of '*materially'*.
629 NER, clause 6A.6.9.
630 NER, chapter 10, definition of '*nominated pass through event considerations'*, subclause (d)(1).
631 NER, chapter 10, definition of '*nominated pass through event considerations'*, subclause (d)(2).
632 ElectraNet, *Pass through event proposal,* 29 August, p. 10.
633 Marsh, *Quantification of the cost of specific low probability, high impact events and associated availability of commercial insurance*, 16 September, p. 2.
634 Powerlink is the transmission network service provider in Queensland.
635 AER, *Draft decision, Powerlink transmission determination 2012–17*, November 2011, p. 196.

We are also required to consider whether the event can be self insured, such that it is possible to calculate the self insurance premium and the potential cost would not have a significant impact on the service provider's ability to provide network services. We consider a natural disaster event that is less than serious and significant can be self insured.

In our draft decision, we considered that a major natural disaster event may not be self insured, in that a self insurance premium could not be calculated and the potential loss to ElectraNet would have a significant impact of ElectraNet's ability to provide network services.[636] However, these reasons hold only if the pass through is limited to major events that potentially cause very high costs to the business. If the definition of natural disaster includes all events that meet the materiality threshold of 1 per cent of maximum allowed revenue, then:

- ElectraNet could reasonably be expected to calculate a self insurance allowance for those risks
- such events may not have a significant impact on ElectraNet's ability to provide network services.

An indication of whether a significant and serious fire, earthquake or flood event has occurred may be if that event has been declared by a relevant government to constitute a 'natural disaster event'.

Manageable risk should remain with ElectraNet

We consider risk would be transferred from ElectraNet to its customers if we do not clarify the definition of a 'major' natural disaster. While low frequency / high severity events may have a significant financial impact, ElectraNet is best placed to identify, manage and finance the risks of those events.

Efficient insurance incentives

A key consideration of any pass through event is that it does not create disincentives for the business to insure or self insure.

If ElectraNet is eligible for a natural disaster event pass through when the cost of the event is not high, it may create a disincentive for ElectraNet to obtain an efficient level of insurance coverage or self insurance. That is, ElectraNet may have an incentive to retain any cost savings while managing its level of risk through the pass through mechanism. We consider that this risk can be reduced by clarifying that the natural disaster event must be a 'major' natural disaster event, in the sense that it is serious and significant.

Insurance cap event

In its revised proposal, ElectraNet did not adopt two aspects of the insurance cap event definition in our draft decision, and proposed amendments to address them.[637] Our final decision largely accepts ElectraNet's proposed amendments. We have also amended the definition to clarify what is meant by 'costs'.

ElectraNet's proposed amendment to address policy limits

ElectraNet proposed amendments to allow an insurance cap event to be triggered in circumstances when it would have been entitled to receive a payment under a relevant insurance policy, but for the

636 AER, Draft decision: ElectraNet transmission determination, November 2012, p. 25.
637 ElectraNet, revised revenue proposal, pp. 178-181.

application of a policy limit (such as a limit on the number of claims or an aggregated total). We agree with the amendments, as the event is intended to be triggered in these circumstances.

ElectraNet's proposed amendment to address policies held in a previous regulatory period

ElectraNet proposed an amendment to clarify that the relevant 'policy limit' could include a policy limit that applied during an earlier regulatory control period, as well as during the 2013–18 regulatory control period. This is because an event that gives rise to an insurance cap event may have occurred in an earlier regulatory control period. In this case, the policy limit operating in that earlier regulatory control period would be the relevant policy limit. We agree that the definition should be amended to address this matter, but we have a minor concern with ElectraNet's proposed wording.

ElectraNet's proposed amendment referred to 'the allowance for insurance premiums approved in the AER's final decision'. However, we do not explicitly include allowances for insurance premiums in our final decision. Rather we approve a total opex forecast. When we raised this concern with ElectraNet they suggested the following words:

> 4b. the policy limit that is <u>explicitly or implicitly</u> commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the relevant insurance policy is issued.

We consider that the inclusion of the words 'explicitly or implicitly' in paragraph 4(b) addresses our concern. We therefore agree with the amendments proposed by ElectraNet.

AER's amendment to clarify the meaning of costs

We also included an amendment to clarify that the costs that ElectraNet incurs beyond the relevant policy limit are those costs that would have been recovered under the insurance policy limit had the limit not been exhausted. ElectraNet did not object to this clarification being included.[638]

Additional pass though event

We do not accept the additional nominated pass through event submitted by ElectraNet in its revised revenue proposal, because ElectraNet submitted the proposed event after the date permitted by the NER.

Further, we do not propose to nominate a pass through event of our own accord (as proposed by ElectraNet), because we are not satisfied that any pass through event nominated by us will meet the NER pass through event considerations, because:

- ElectraNet did not clearly identify the nature or type of event[639]
- the NER already provides pass through events that may allow ElectraNet to recover additional capital costs incurred as a result of a regulatory change event or a service standard event.[640]

[638] ElectraNet, *Email response to information request AER RRP18, Nominated pass through event definitions*, ENET366, 26 March 2013, p. 3.
[639] NER, Chapter 10, Glossary, *nominated pass through event considerations*, 6A.7.3(a1)(5).
[640] Chapter 10, Glossary, nominated pass through event considerations, 6A.7.3(a1)(5).

Timeframe to submit nominated pass through event

The transitional provisions in the NER permitted ElectraNet to propose pass through events for its revenue proposal, no later than 30 days after 2 August 2012.[641] ElectraNet submitted its revised revenue proposal on 16 January 2013. Accordingly, ElectraNet's proposal was not made in the time specified in the NER. The NER does not expressly allow us to accept a nominated cost pass through event that is made out of time.

However, we also considered whether to nominate a pass through event of our own accord. Clause 6A.7.3(a1)(5) states that a pass through event is 'any other event specified in a transmission determination as a pass through event for the determination.' We consider that, under this clause, we are able to include a pass through event in a revenue determination where that event relates to an issue raised in the revised revenue proposal.

However, we do not consider that including the pass through event in the form proposed by ElectraNet is appropriate, having regard to the nominated pass through event considerations. We do not accept the event because:

- the nature or type of ElectraNet's proposed event is not clearly identified
- the proposed event may be covered by another pass through event.[642]

Whether the nature or type of event can be clearly identified

We consider that ElectraNet has not clearly identified the proposed pass through event. ElectraNet's revised proposal describes the nominated pass through event as follows:

> [An] event which would be triggered by a decision from ESCOSA that results in a more onerous forecast demand obligation under the ETC.

We consider that the phrase 'forecast demand obligation' does not clearly identify the nature or type of event, or the circumstances that constitute a more onerous forecast demand obligation. It also suggests a current forecast demand obligation exists against which the changed obligation is to be measured.

As discussed in our draft decision, the South Australian ETC imposes an obligation to react to a change in forecast agreed maximum demand (FAMD), not an obligation to forecast demand.[643] Forecast agreed maximum demand is a definition that describes a level of demand that is agreed between SA Power Networks and ElectraNet three years in advance.[644] It is a level of demand each anticipates having to meet three years in the future. As such it is a planning tool that allows ElectraNet to ascertain whether it may need to augment its network or adopt other demand management strategies in the future in order to be able to contract at that level of demand. We note that there is no obligation in the ETC that requires ElectraNet to contract at FAMD. Further, nothing in the ETC obliges ElectraNet to contract at a level of demand that it cannot reliably supply.

In our draft decision,[645] we noted that any obligations imposed under the ETC are in addition to those imposed under the NER[646] and that the provisions of the NER have priority to the extent of any

641 NER, clause 11.49.4.
642 We did not decide whether ElectraNet's proposed pass through is covered by another category of pass through event, primarily because ElectraNet did not clearly define its proposed event.
643 AER, Draft decision: ElectraNet transmission determination, November 2012, pp.25 and attachment 2, section 2.5, p. 87.
644 ETC, TC/07, clause 10, p. 23.
645 AER, Draft decision: ElectraNet transmission determination, November 2012, p. 91.
646 ETC, TC/06 and ETC TC/07, clause 1.6.1.

inconsistency.[647] The exception is where the ETC imposes an obligation that is 'higher or more onerous' than any corresponding obligation contained in the NER. For a revenue proposal, the NER requires ElectraNet to propose the total forecast capex it requires to meet expected demand.[648] We must be satisfied that ElectraNet's forecast demand is a realistic expectation of demand for the regulatory control period. As the ETC does not impose an obligation to forecast demand for the regulatory control period, it does not impose an obligation that is 'higher or more onerous' than the one in the NER.

It is not clear how a change to the definition of FAMD in the ETC will result in a more onerous obligation to forecast demand. FAMD as it is currently defined does not create an obligation to forecast demand for the regulatory control period. As a result it does not impact our assessment of whether ElectraNet's total forecast capex meets the capex criteria. That assessment is based on whether ElectraNet's forecast capex reflects a realistic expectation of demand not whether it meets the definition of FAMD.

We note ESCOSA's recent draft decision regarding ElectraNet's application to amend the definition of FAMD to a level of demand that is derived by adopting a particular forecasting methodology.[649] ESCOSA decided it will not amend the ETC. As a result, ElectraNet's obligations under the ETC remain unchanged and ElectraNet has not been disadvantaged by ESCOSA's decision.

Lastly, ElectraNet's proposed event does not define the threshold that is to apply. That is, it does not specify how the increase or decrease in costs is to be determined so its impact on costs may be assessed. The definition should specify how the change in costs is to be measured against the allowance for those costs for a specified regulatory year.

Whether the event is covered by another category of pass through event

Despite not being clearly identified, ElectraNet's proposed pass through event may be covered by:

- a service standard event[650]
- a regulatory change event.[651]

If the proposed event is covered by either of these two events, then it does not qualify as 'any other event' under clause 6A.7.3(a1)(5).

A service standard event is defined in the NER[652]. In general, it is an event that changes the manner in which a TNSP is required to provide prescribed transmission services or the minimum service standards that it must meet. The event must materially increase or decrease the costs to the TNSP in providing the prescribed transmission services.[653]

A regulatory change event is also defined in the NER.[654] Generally, it is a change in a regulatory obligation or requirement that substantially affects the manner in which the TNSP provides prescribed transmission services. It too must materially increase or decrease the costs of providing those services.

647 ETC, TC/07, clause 1.6.2.
648 NER, clause 6A.6.7(a)(1).
649 ESCOSA, *Draft decision on Electranet's proposed amendments to revised electricity transmission code*, 5 April 2013.
650 NER, clause 6A.7.3(a1)(2).
651 NER, clause 6A.7.3(a1)(1).
652 NER, chapter 10 - Glossary, definition of *service standard event*, p.1177.
653 NER, chapter 10 - Glossary, definition of *materially*, p. 1137. The NER defines *materially* as a change in costs that exceeds 1 per cent of the *maximum allowed revenue* for that *regulatory year*.
654 NER, Chapter 10 - Glossary, p.1165.

We accept that obligations under the ETC are regulatory obligations. So, any material change in an ETC obligation that substantially affects the manner in which ElectraNet provides prescribed transmission services is likely to fall within the definition of a regulatory change event.

We also accept that the ETC imposes obligations on ElectraNet regarding the standard of reliability it must meet in the planning, development or operation of the transmission network and the supply of transmission services. These obligations are relevant to the manner in which ElectraNet provides prescribed transmission services and the minimum service standards it must meet in doing so. A decision to change ETC obligations thus has the potential to be a service standard event.

Whether a service standard event or a regulatory change event occurs will be known only if and when ESCOSA makes a decision to change the ETC obligations. ElectraNet can apply to us to pass through the costs associated with such events if and when they occur.

13.5 AER decision

Decision 13.1: The following nominated pass through events will apply to ElectraNet in the 2013–18 regulatory control period, as defined in section 13.1:

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

Part 3 – Appendices

A List of submissions

Table A.1 List of submissions on AER's draft decision and ElectraNet's revised revenue proposal

Submission	Date submitted
Centrex Metals	19 February 2013
Energy Consumers Coalition of South Australia (ECCSA)	19 February 2013
Energy Users Association of Australia (EUAA)	19 February 2013
Eyre Peninsula Local Government Association	11 December 2012
Iron Road	19 February 2013
South Australia Government – Resources and Energy Sector Infrastructure Council	26 February 2013
South Australia Government – Hon Tom Koutsantonis MP, Minister for Mineral Resources and Energy	2 March 2013
Transend	19 February 2013
TransGrid	19 February 2013

B Contingent projects

Table B.1 Contingent project not accepted by the AER

ElectraNet number	Project Name	Proposed trigger event	Cost $ million (nominal)
8	Northern Suburbs reinforcement	1. Load growth in the distribution system in the northern suburbs region that causes: - the total load on the Para to Elizabeth Heights 66 kV sub-transmission line to exceed its thermal rating (137 MVA) for an outage of the Munno Para 275/66 kV transformer; OR - the need to de-radialise supply to Gawler East. 2. Successful completion of the regulatory test or regulatory investment test for transmission (as applicable) including a comprehensive assessment of credible options demonstrating that a new or modified transmission connection point in the region is economically justified 3. Formal request for a new regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	50

Source: ElectraNet, *Revised revenue proposal,* p. 177.

Table B.2 Contingent projects accepted by the AER without modification to the trigger event

ElectraNet number	Project Name	Trigger event as accepted by the AER	Cost $ million (nominal)
5	South East to Heywood interconnection upgrade	1. Successful completion of the regulatory investment test for transmission demonstrating positive net market benefits, 2. Determination by the AER under clause 5.16.6 that the proposed investment satisfies the regulatory investment test for transmission, and 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules	63
6	Davenport reactive support	1. Commitment to the temporary or permanent closure of Playford and Northern Power Stations during the South Australian summer period, 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified, and 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	42

Source: ElectraNet, *Revised revenue proposal,* p. 178.

Table B.3 Contingent projects accepted by the AER with revised trigger events – load driven projects

ElectraNet number	Project Name	Proposed trigger event	Revised trigger event	Cost $ million (nominal)
1	Lower Eyre Peninsula reinforcement	1. Customer commitment to a step load increase exceeding 50 MW on the transmission network south of Cultana substation, causing the Cultana to Yadnarie 132 kV transmission line to exceed its thermal limit (73 MVA) 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1. Customer commitment for major new mining loads to connect to the transmission network south of Cultana resulting in a step load increase in demand: - exceeding 50 MW, over and above ElectraNet's 2012–13 10% PoE demand forecast of 87.5 MW, - at Port Lincoln, Middleback, Yadnarie, Wudinna, or any additional connection points established in this vicinity, and - causing the Cultana to Yadnarie 132 kV transmission line to exceed its thermal limit of 73 MVA, 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified, and 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	340
11	Upper North Region line reinforcement	1. Customer commitment to connect a step load along the Davenport to Pimba 132 kV transmission line that causes the total load to exceed 76 MW causing thermal limitations on the network 2. Completion of the regulatory investment test for transmission including a comprehensive assessment of credible options demonstrating that reinforcement of the transmission line is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1. Customer commitment for major new mining loads to connect to the transmission network north of Davenport resulting in a step load increase in demand: - exceeding 40 MW, over and above ElectraNet's 2012–13 10% PoE demand forecast of 34 MW, - at Mount Gunson, Woomera, Olympic Dam North, or any additional connection points established in this vicinity, and - causing the Davenport to Pimba 132 kV line to exceed its thermal limit of 76 MVA, 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified, and	60

			3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	
4	Yorke Peninsula reinforcement	1. Customer commitment to a step load increase exceeding 60 MW on the transmission network south of Ardrossan West substation, causing the Bungama to Snowtown to Hummocks 132 kV transmission line to exceed its thermal limit (105 MVA) on loss of the Waterloo to Hummocks 132 kV transmission line (and vice versa) 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing that reinforcement of the transmission network supplying Hummocks is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1. Customer commitment for major new mining loads to connect to the transmission network south of Hummocks resulting in a step load increase: - exceeding 60 MW, over and above the 2012–13 10% PoE demand forecast of 52 MW, - at Ardrossan West, Kadina East, Dalrymple, or any additional connection points established in this vicinity, and - causing the Bungama to Snowtown to Hummocks 132 kV transmission line to exceed its thermal limit of 105 MVA on loss of the Waterloo to Hummocks 132 kV transmission line (and vice versa), 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified, and 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	190
12	East Terrace transformer	1. Forecast load exceeding 270 MVA in the Adelaide Central Region 2. Completion of the regulatory investment test for transmission including a comprehensive assessment of credible options demonstrating that a second transformer at East Terrace substation is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1. Customer commitment for the hospital precinct, rail electrification or other load (s) to connect to the distribution network in the Adelaide Central Region resulting in an aggregate step load increase in demand: - exceeding 19 MW, over and above the 2017–18 10% PoE demand forecast of 247 MW published in 2012, and - causing the East Terrace transformer to exceed its thermal limit of 270 MVA on loss of the City West 275/66 kV transformer, 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified, and 3. ElectraNet Board commitment to proceed with the project subject to the AER amending	23

			the revenue determination pursuant to the Rules.	
10	Port Pirie system reinforcement	1. Addition of a step load in the Port Pirie area that causes: - the total load on the Bungama to Port Pirie 33 kV sub-transmission lines to exceed their thermal rating (84 MVA) for an outage of the Bungama to Port Pirie 132 kV transmission line or Port Pirie 132/33 kV transformer; OR - the total load on the grouped Bungama to Port Pirie connection points exceeding 93 MVA causing low voltage at Bungama for the loss of the single 200 MVA 275/132 kV transformer 2. Successful completion of the Regulatory Test or regulatory investment test for transmission (as applicable), including a comprehensive assessment of credible options demonstrating that a transmission reinforcement in the region is economically justified 3. Formal request for an expanded regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1. Customer commitment for a smelter or other load in the Port Pirie area resulting in a step load increase in demand: - exceeding 10 MW, over and above the 2012–13 10% PoE demand forecast of 81 MW, and causing: a. the total load on the Bungama to Port Pirie 33 kV distribution lines to exceed their combined thermal rating of 84 MVA for an outage of the Bungama to Port Pirie 132 kV transmission line or Port Pirie 132/33 kV transformer; OR b. the total load on the grouped Bungama to Port Pirie connection points to exceed 93 MVA causing low voltage at Bungama for the loss of the single 200 MVA 275/132 kV transformer, 2. Successful completion of the regulatory investment test for transmission or the regulatory investment test for distribution (as applicable) including a comprehensive assessment of credible options showing a transmission investment is justified, and 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	52
9	Mid North connection point	1. Addition of a step load to the distribution system, in the upper north east of the mid-north region that causes the total load on the Bungama to Gladstone 33 kV sub-transmission line to exceed 14 MVA and causing voltage limitations in the distribution network 2. Successful completion of the regulatory test or regulatory investment test for transmission (as applicable), including a comprehensive assessment of credible options demonstrating that a transmission reinforcement in the region is	1. Customer commitment for new mining load(s) to connect to the distribution network near Yunta resulting in a step load increase in demand: - exceeding 5MW, and - causing SA Power Networks Bungama to Gladstone 33 kV distribution line loading to exceed 14MVA, and - causing voltage limitations in the distribution system 2. Successful completion of the regulatory investment test for transmission or the regulatory investment test for distribution(as applicable) including a comprehensive assessment of	60

		economically justified 3. Formal request for a new regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	credible options showing a transmission investment is justified 3. Formal request for a new regulated connection point from the DNSP, and 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	

Source: ElectraNet, *Revised revenue proposal,* pp. 176–179.

Table B.4 Contingent projects accepted by the AER with revised trigger events – non-load driven projects

ElectraNet number	Project Name	Proposed trigger event	Revised trigger event	Cost $ million (nominal)
7	Upper South East network augmentation	1. Publication by AEMO of evidence of material constraints in the South East region of the transmission network 2. Successful completion of the regulatory investment test for transmission demonstrating positive net market benefits 3. Determination by the AER under clause 5.6.6AA that the proposed investment satisfies the regulatory investment test for transmission 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1a. Publication by AEMO of evidence of material constraints in the transmission network in the upper part of the south east region, OR 1b. A generator connection of greater than 250MW in the upper part of the south east region, 2. Successful completion of the regulatory investment test for transmission demonstrating positive net market benefits, 3. Determination by the AER under clause 5.16.6 that the proposed investment satisfies the regulatory investment test for transmission, and 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	50
2	Riverland reinforcement	1. Publication by AEMO of available Murraylink dispatch into South Australia that is insufficient to provide adequate support to the Riverland causing thermal limitations on the Robertstown to Berri transmission lines 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options	1. Publication (or demonstration) 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 and breaching the ETC, 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified, and	400

		demonstrating that reinforcement of the Riverland is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	
3	Fleurieu Peninsula reinforcement	1. Load growth in the distribution system in the Fleurieu Peninsula region that causes the total load on the Willunga to Square Water Hole 66 kV subtransmission line to exceed its thermal limit (72 MVA) 2. Successful completion of the Regulatory Test by the DNSP including a comprehensive assessment of credible options showing a transmission solution is economically justified 3. Formal request for a new regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	1. Failure of the non-network solution (the proposed generator[655]) as a technically and economically viable option, 2. Successful completion of the regulatory investment test for transmission, the regulatory investment test for distribution or the Regulatory Test (as applicable) including a comprehensive assessment of credible options showing a transmission investment is justified, 3. Formal request for a new regulated connection point from the DNSP, and 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	210

Source: ElectraNet, *Revised revenue proposal*, pp. 177–178.

655 ElectraNet, ENET347, p. 3 [Confidential].

C Consultation and engagement with stakeholders

We set out below the key meetings with ElectraNet and other stakeholders undertaken by us in making this final decision on ElectraNet's revenue proposal for the regulatory control period 2013–2018.

Table C.1 Consultation and engagement meetings

Date	Parties	Subject of discussion
1 October 2011	AER staff, ElectraNet	Pre lodgement meeting
2 December 2011	AER staff, ElectraNet	Pre lodgement meeting
3 February 2011	AER staff, ElectraNet	Pre lodgement meeting
Revenue proposal – 30 May 2012		
7 June 2012	AER staff, AEMO, EMCa*, ElectraNet	AEMO's Capital project assessment report
12 June 2012	AER staff, EMCa, ESCOSA	Electricity Transmission Code (ETC)/Demand
12 June 2012	AER staff, EMCa, ElectraNet, SAPN	SAPN demand forecasts
12 June 2012	AER staff, SA Department of Energy (DMITRE)	Revenue proposal in general
25 June - 6 July 2012	AER staff, EMCa, ElectraNet	On site review ElectraNet's proposal
22 June 2012	AER Board, ElectraNet CEO	ElectraNet presentation to AER board
23 July 2012	AER hosts public forum	Opportunity for stakeholders to directly engage with ElectraNet
2 August 2012	AER staff, EMCa, NZIER, AEMO	SA demand forecasts
6 August 2012	AER staff, ElectraNet	Proposed pricing methodology
17 August 2012	AER staff, ESCOSA	ETC/demand forecast
22 August 2012	AER staff, EMCa, ElectraNet	Contingent projects
13 September 2012	AER staff, ElectraNet	Initial technical findings briefing
2 October 2012	AER staff, McGrath Nicol, ElectraNet	Cost allocation methodology
3 October 2012	AER staff, EMCa, ElectraNet	Technical findings workshop
4 October 2012	AER staff, EMCa, ElectraNet	Contingent projects workshop
5 October 2012	AER staff, EMCa, ElectraNet, SA Water	Connection point replacement capex (written response from SA Water)
17 October 2012	AER staff, ElectraNet	Opex modelling
22 October 2012	AER staff, AEMO	SA demand forecasts
7 November 2012	AER staff, ElectraNet	Capex modelling

Draft decision – 30 November 2012		
4 December 2012	AER Chairman, ElectraNet	ElectraNet's proposed ETC changes
7 December 2012	AER staff, ElectraNet	AER draft decision opex/capex models
11 December 2012	AER staff, ElectraNet	AER draft decision EBSS model
12 December 2012	AER pre determination conference	AER chairman presented draft decision EUAA presented its views on draft decision
19 December 2013	AER staff, ElectraNet	Contingent projects
8 January 2013	AER staff, ElectraNet	Revised proposal – pre lodgement update
11 January 2013	AER staff, ElectraNet, PWC	EBSS
13 February 2013	AER staff, ElectraNet	Revised proposal opex/capex models
15 February 2013	AER Board, ElectraNet	ElectraNet presentation to the AER board
21 February 2013	AER staff, ElectraNet	Contingent projects
26 February 2013	AER staff, EMCa, ElectraNet	Contingent projects
6 March 2013	AER staff, EMCa, ElectraNet, Evans & Peck	Evans and Peck statistical analysis (cost estimation risks)
11 April 2013	AER staff, ElectraNet	ElectraNet's proposed ETC change
16 April 2013	AER staff, ElectraNet	AER final decision opex/capex modelling

*References to EMCa include Strata Energy Consulting and NZIER where relevant.