Stage 2 Framework and approach

Ausgrid, Endeavour Energy and Essential Energy

Transitional regulatory control period
1 July 2014 to 30 June 2015

Subsequent regulatory control period
1 July 2015 to 30 June 2019

January 2014

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Contents

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
capex incentive guideline	Capital expenditure incentive guideline for electricity network service providers
CESS	capital expenditure sharing scheme
CPI	consumer price index
current regulatory control period	1 July 2009 to 30 June 2014
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
Expenditure assessment guideline	Expenditure forecast assessment guideline for electricity distribution
F&A	Framework and approach
GSL	guaranteed service level
IPART	Independent Pricing and Regulatory Tribunal of NSW
kWh	kilowatt hours
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
NPV	net present value
NSW	New South Wales
opex	operating expenditure
RAB	regulatory asset base
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCER	Standing Council on Energy and Resources
STPIS	service target performance incentive scheme
subsequent regulatory control	1 July 2015 to 30 June 2019

period	
transitional regulatory control period	1 July 2014 to 30 June 2015
VCR	value of customer reliability
WAPC	weighted average price cap

About the framework and approach

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution services in Australia's national electricity market (NEM).[1] We are an independent statutory authority, funded by the Australian Government. Our powers and functions are set out in the National Electricity Law (NEL) and National Electricity Rules (the rules or NER).

The framework and approach (F&A) is the first step in a process to determine efficient prices for electricity distribution services. The F&A determines, amongst other things, which services we will regulate and how we propose to apply the relevant incentive schemes. It also facilitates public consultation and assists distribution network service providers (distributors) to prepare regulatory proposals.

Ausgrid, Endeavour Energy and Essential Energy are licensed, regulated operators of New South Wales (NSW) monopoly electricity distribution networks. The networks comprise the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. These NSW distributors design, construct, operate and maintain distribution networks for NSW electricity consumers. The current five year distribution determinations that set revenue allowances for these distribution businesses conclude on 30 June 2014.

On 29 November 2013 the Australian Energy Market Commission (AEMC) published changes to the rules governing network regulation. The new rules require us to set out our approach to network regulation under the new framework in a series of guidelines. We commenced the Better Regulation program on 18 December 2012 to consult on our approach and published our final guidelines in November and December 2013.

The AEMC developed transitional rules to allow time for us to consult on the guidelines and to clarify how our new approach will apply to NSW distributors. The transitional rules separate the 2014–19 regulatory control period into two periods: a one year transitional regulatory control period commencing 1 July 2014 and ending 30 June 2015 (the transitional period) and a subsequent regulatory control period covering the remaining years which commences 1 July 2015 and ends 30 June 2019 (the subsequent period).

The transitional rules require us to publish the NSW F&A in two stages.[2] The Stage 1 F&A and Stage 2 F&A set out our approach to issues for both the transitional period and subsequent period.

We published the Stage 1 F&A on 25 March 2013. It set out our decisions on:[3]

- distribution service classification
- control mechanisms and the formulae that give effect to the control mechanisms
- dual function assets.

This Stage 2 F&A sets out our proposed approach on the application of any:[4]

- service target performance incentive scheme (STPIS)

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[1] In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules.

[2] Prior to the November 2012 rule changes, a single final F&A was required.

[3] NER, clause 11.56.4(l)(1).

[4] NER, clause 11.56.4(l)(2).

- efficiency benefit sharing scheme (EBSS)
- capital expenditure sharing scheme (CESS)
- demand management incentive scheme (DMIS)
- expenditure forecast assessment guidelines
- approach to calculating depreciation.

Where relevant, we have taken into account submissions on the Preliminary F&A published in June 2012.[5] We have also consulted with distributors on the positions set out in this document.

Part A of this Stage 2 F&A sets out an overview of our decisions and reasons for each of the above matters. Part B sets out in Attachments 1 to 7 our substantive reasoning for each matter.

Following release of the Stage 1 and 2 F&A, NSW distributors will submit regulatory proposals in early 2014. Table 1 summarises the NSW distribution determination process.

Table 1 NSW distribution determination process

Step	Date
AER published preliminary positions F&A for NSW distributors	25 June 2012
AER published Stage 1 F&A for NSW distributors	25 March 2013
AER to publish Stage 2 F&A for NSW distributors	31 January 2014
Distributors submit transitional regulatory proposal to AER	31 January 2014
AER to publish distribution determination for transitional regulatory control period	30 April 2014
Distributors submit subsequent regulatory proposal to AER	31 May 2014
Submissions on subsequent regulatory proposal close	August 2014**
AER to publish draft distribution determination	November 2014*
AER hold public forum on draft distribution determination	December 2014**
Distributors to submit revised subsequent regulatory proposal to AER	January 2015
Submissions on revised subsequent regulatory proposal and draft determination close	February 2015**
AER to publish distribution determination for subsequent regulatory control period	30 April 2015

Source: NER, chapter 6, Part E.
*The rules do not provide specific timeframes for publishing draft decisions. So this date is indicative only.
** The dates provided for submissions and the public forum are based on us receiving compliant proposals. These dates may alter if we receive non-compliant proposals.

5 Our Preliminary F&A set out our likely approach to distribution service classification (which services are to be regulated); control mechanisms (how will prices be determined) and the formulae that give effect to the control mechanisms; dual function assets (how will transmission type assets be treated); and the application of incentive schemes. AER, *Preliminary positions Framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy—Regulatory control period commencing 1 July 2014*, 25 June 2012.

Part A: Overview

This Stage 2 F&A covers how we propose to apply a range of incentive schemes and other guidelines to the NSW distribution businesses, as well as our approach to calculating depreciation.

Incentive schemes encourage distributors to manage their businesses in a safe, reliable manner that services the long term interests of consumers. The schemes also provide distributors with incentives to spend efficiently and to meet or exceed service quality targets. In some instances, distributors may incur a financial penalty if they fail to meet set targets. The overall objectives of the schemes are to:

- encourage appropriate levels of service quality
- maintain network reliability as appropriate
- incentivise distributors to spend efficiently on capital expenditure (capex) and operating expenditure (opex)
- share efficiency gains and losses between distributors and consumers
- incentivise distributors to consider economically efficient alternatives to building more network.

We summarise the specific schemes below, and also provide an overview of our expenditure forecast assessment guideline and approach to calculating depreciation.

Service target performance incentive scheme

Our national STPIS provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to safeguard service quality for customers against incentives for the distributors to seek out cost efficiencies.

We propose not to apply our national STPIS to the NSW distributors in the transitional period. The current performance reporting obligations will continue to apply with no revenue at risk. We propose to apply the service standards factor (s-factor) component of our national STPIS to the NSW distributors in the subsequent period. The jurisdictional guaranteed service level (GSL) arrangements will continue to apply in the transitional and subsequent periods.

Efficiency benefit sharing scheme

The EBSS aims to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices.

As part of our Better Regulation program we consulted on and published version 2 of the EBSS. We propose to apply this new EBSS to the NSW distributors in both the transitional period and subsequent period.

Capital expenditure sharing scheme

The CESS provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

As part of our Better Regulation program we consulted on and published version 1 of the capital expenditure incentive guideline for electricity network service providers (capex incentive guideline) which sets out the CESS. The transitional rules specify that no CESS applies to the NSW distributors for the transitional period.[6] We propose to apply the CESS to NSW distributors in the subsequent period.

Demand management incentive scheme

The DMIS is one mechanism to incentivise distributors to consider economically efficient alternatives to building more network. NSW distributors are currently subject to a DMIS with two components—the demand management innovation allowance (DMIA) and the D-factor.

We propose to continue applying the DMIA to NSW distributors in the transitional period and subsequent period. But, we propose to discontinue the D-Factor scheme for NSW distributors from the transitional period onwards.

The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. Whether we are able to develop and implement a new DMIS for the subsequent period, depends on the progress of the rule change process and the inclusion of any relevant transitional provisions.

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.[7] We have not developed this scheme. Therefore, we will not be stating our proposed approach on the application of this scheme to the NSW distributors.

Expenditure forecast assessment guideline

As part of our Better Regulation program we consulted on and published our expenditure forecast assessment guideline for electricity distribution (expenditure assessment guideline). The expenditure assessment guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. Our proposed approach is to apply the expenditure assessment guideline, including the information requirements to the NSW distributors in the subsequent regulatory control period.

The expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the NSW distributors' regulatory proposals. We intend to apply all the assessment tools set out in the expenditure assessment guideline.

Depreciation

As part of the roll forward methodology, when a distributor's regulatory asset base (RAB) is updated from forecast capex to actual capex at the end of a regulatory period, it is also adjusted for depreciation. The depreciation we use to roll forward the RAB can be based on either actual capex incurred during the regulatory control period, or the capex allowance forecast at the start of the regulatory control period. The choice of depreciation approach is one part of the overall capex incentive framework. Consumers benefit from improved efficiencies through lower regulated prices.

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6 NER, clause 11.56.3(a)(3).

7 NER, clause 6.6.4.

We propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2019–24 regulatory control period NSW distributors.

Residual issues from our Stage 1 F&A

This section clarifies specific aspects of our decisions set out in the Stage 1 F&A.[8]

Control mechanism for dual function assets

Dual function assets are the parts of a distributor's network that operate in a way that supports the transportation of electricity over the higher voltage transmission network.[9] The rules allow distributors to address dual function assets in a distribution determination to avoid the need for separate transmission revenue proposals.[10]

Our decision on the pricing of dual function assets in the Stage 1 F&A is final and binding. The current approach to dual function assets will continue to apply in the transitional year. For the subsequent period, our approach is to:

- apply transmission pricing to Ausgrid's dual function services
- apply distribution pricing to Endeavour Energy's dual function services
- Essential Energy does not own, operate or control dual function assets, so we were not required to outline our approach.

In our determination for Ausgrid, we are required to divide revenue for standard control services into:

- a transmission portion for services provided dual function assets; and
- a distribution portion for other standard control services.[11]

Ausgrid's standard control services will be under a revenue cap in the next regulatory control period. We outlined the formulae giving effect to this control mechanism in our Stage 1 F&A.[12] Separate revenue caps will apply (with different X factors[13]) for the transmission and distribution portions of revenue for standard control services.

Alternative control services prices

As outlined in the Stage 1 F&A, we will cap the prices of all individual standard control services in the transitional and subsequent periods.[14] We proposed to classify the following services as alternative control services:

- metering services—types 5 and 6 metering provision, maintenance, reading and data services
- ancillary network services
- public lighting services (excluding emerging public lighting technologies).

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8 AER, *Stage 1 Framework and approach paper: Ausgrid, Endeavour Energy and Essential Energy—Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, 25 March 2013. (AER, *Stage 1 Framework and approach paper for NSW distributors*, Mar 2013).

9 NER, cl. 6.24.2(a).

10 NER, cl. 6.24.

11 NER, cl. 6.26(b).

12 AER, *Stage 1 Framework and approach paper for NSW distributors*, Mar 2013, p. 43.

13 NER, cl. 6.5.9(c).

14 AER, *Stage 1 Framework and approach paper for NSW distributors*, Mar 2013, p. 43.

In our determinations, we will outline how we will set the price caps for alternative control services, that is, whether we will use a building block approach or another method.

Pricing of alternative control services in transitional period are governed under the transitional rules. The rules allow for a placeholder determination while we complete our full determination. We will consider whether or not a true up of placeholder prices for alternative control services is required as part of our determination for each business. Any true-up will be in accordance with the rules.

Control mechanism for quoted services

We will set the prices of the following ancillary network services on a quoted basis:

- reinspection of installation work in relation to customer assets
- off-peak conversion
- rectification works
- connection/relocation process facilitation
- investigation, review and implementation of remedial action association with ASPs' connection work

We will derive the prices of quoted services from their relevant input costs (e.g. labour rate, material cost). Each year of the next regulatory period, we will set the price of each quoted service by substituting the input cost of each for $\overline{p}_i^{t-1}$ in section 2.5.6 of our Stage 1 F&A.[15]

Confidentiality

As part of the Better Regulation Reform program we recently published our confidentiality guideline.[16] This sets out how the distributors must make confidentiality claims over information they submit to us. Under the rules,[17] the confidentiality guideline applies and is binding on the following documents pertaining to distributor's regulatory proposals:

- initial and revised regulatory proposal
- initial and revised revenue proposal
- proposed and revised proposed negotiating framework
- proposed and revised proposed pricing methodology.

15 AER, *Stage 1 Framework and approach paper for NSW distributors*, Mar 2013, p. 60.
16 AER, *Confidentiality guideline*, 19 November 2013.
17 NER, cl.6.14A(b) & (d), & cl.6A.16A(b) & (d).

Part B: Attachments

1 Service target performance incentive scheme

This attachment sets out our proposed approach and reasons for applying the service target performance incentive scheme (STPIS) to the NSW distributors in the next regulatory control period.

Our national distribution STPIS[18] provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the national electricity objective (NEO).

The STPIS operates as part of the building block determination and contains two mechanisms:

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers[19] experiencing service below a predetermined level.[20]

While the mechanics of how the STPIS will operate are outlined in our national distribution STPIS, we must set out key aspects specific to each distributor in the next regulatory control period at the determination stage, including:

- the maximum revenue at risk under the STPIS
- how the distributor's network will be segmented
- the applicable parameters for the s-factor adjustment of annual revenue across customer service, reliability and quality of supply components
- performance targets for the applicable parameters in each network segment
- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates determining the relative importance of measured performance (against targets) across applicable parameters in each network segment.

Distributors can propose to vary the application of the STPIS in their regulatory proposal.[21] We can accept or reject the proposed variation in our determination. Each applicable year we will calculate a distributor's s-factor based on its service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility

18 AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009. (AER, *Electricity distribution STPIS*, Nov 2009).

19 Except where a jurisdictional electricity GSL requirement applies.

20 Service level is assessed (unless we determine otherwise) with respect to parameters pertaining to the frequency and duration of interruptions; and time taken for streetlight repair, new connections and publication of notices for planned interruptions.

21 AER, AER, *Electricity distribution STPIS*, Nov 2009, clause 2.2.

for customers.[22] A distributor proposing a delay must provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers.

Our national STPIS does not currently apply in NSW. That is, NSW distributors are not currently subject to financial penalty or reward through an s-factor adjustment to revenue. However, jurisdictional GSL arrangements do apply. At the time of the 2009 determinations, we did not consider the NSW distributors had sufficient relevant historical data to establish service performance targets.[23]

1.1 AER's proposed approach

We propose to not apply our national STPIS to the NSW distributors in the transitional period. The current performance reporting obligations will continue to apply with no revenue at risk. The rules intend for the transitional year to be subject to a fast-tracked 'placeholder' revenue proposal and determination. There is no formal process for us to outline our proposed application of the STPIS prior to the NSW distributors submitting their transitional proposals.

We propose to apply the s-factor component of our national STPIS to the NSW distributors in the subsequent period. We consider this to be suitable given we now have sufficient historical data (collected over the 2009–14 regulatory control period) with which to set service performance targets.

Our proposed approach to applying the national STPIS in the subsequent period will be to:

- set revenue at risk for each distributor within the range ±5 per cent
- segment the network according to our interpretation of the Standing Committee on National Regulatory Reporting Requirements feeder categories (CBD, urban, short rural and long rural) in the NSW jurisdictional distribution licence conditions
- set applicable parameters to be:
    - for the reliability of supply component: the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI)
    - for the customer service component: telephone answering
- set performance targets based on the distributor's average performance over the past five regulatory years
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates.

Our proposed approach is not to apply the GSL component if the NSW distributors remain subject to jurisdictional GSL arrangements.

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22 AER, *Electricity distribution STPIS*, Nov 2009, clauses 2.5(d),(e).

23 AER, *Final Decision—New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 244.

The NSW distributors put forward a combined submission commenting on our 2012 Preliminary F&A.[24] We address comments regarding our proposed application of the STPIS in section 1.3. We are aware of policy reviews indicating the need to reform the STPIS. The AEMC recently conducted a review of distribution reliability frameworks in the NEM.[25] The Australian Energy Market Operator (AEMO) is currently conducting analysis on how willing consumers are to pay for improvements in network reliability.[26] We consider there is inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for the NSW distributors.

1.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a STPIS for the NSW distributors.[27] These include:

- Jurisdictional obligations:
    - consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
    - ensuring that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation any regulatory obligations or requirements to which the distributor is subject.
- Benefits to consumers:
    - the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
    - the willingness of the customer to pay for improved performance in the delivery of services.
- Balanced incentives:
    - the past performance of the distribution network
    - any other incentives available to the distributor under the rules or the relevant distribution determination
    - the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
    - the possible effects of the schemes on incentives for the implementation of non-network alternatives.

Our approach and reasons for developing the STPIS are contained in our final decision for the national distribution STPIS.[28]

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24 Ausgrid, Endeavour Energy and Essential Energy, *NSW DNSPs' Response to the AER's Preliminary Framework and Approach Paper, Regulatory Control Period Commencing 1 July 2014*, 17 August 2012. (NSW distributors, *Response to AER Preliminary F&A*, Aug 2012).

25 AEMC, *Final Report: Review of the national framework for distribution reliability*, 27 September 2013.

26 AEMO, *Directions paper: Value of customer reliability*, 31 May 2013.

27 NER, clause 6.6.2(b).

28 AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

1.3 Reasons for AER's proposed approach

Our reasons for applying the STPIS to the NSW distributors in the transitional and subsequent periods are set out below.

1.3.1 Jurisdictional obligations

In applying the STPIS, we must have regard to jurisdictional service standards and targets,[29] and any other regulatory obligations or requirements to which distributors are subject.[30]

In NSW, the Independent Pricing and Regulatory Tribunal (IPART) administers and monitors compliance with the distribution licence conditions set by the NSW Department of Trade and Investment. As required by the rules, we will consult with these jurisdictional authorities regarding the implementation of the STPIS[31] before finalising our distribution determination.

Our proposed approach to applying the STPIS in NSW does not intend to compromise the distributors' ability to comply with jurisdictional licence obligations. We will not apply the GSL component of our national STPIS while jurisdictional arrangements are in place.

In their response to the AER's 2012 Preliminary Framework and Approach, the NSW distributors considered the ±5 per cent revenue at risk (as indicated in the national STPIS) to be excessive considering the ongoing uncertainty in the NSW electricity environment.[32] The NSW distributors instead suggested applying a revenue at risk of ±2.5 per cent. Consistent with the objectives of the STPIS, we propose to set revenue at risk reflective of the particular circumstances of each distributor and within the range of ±5 per cent. We will determine the revenue at risk during the distribution process following receipt of the NSW distributors' regulatory proposals and submissions on those proposals.

1.3.2 Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the rules, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.[33]

Under the STPIS, the distributors' financial penalty or reward in each year of the regulatory control period is the change in its annual revenue allowance after the s-factor adjustment. Economic analysis of the value consumers place on improved service performance is an important input to the administration of the scheme. Value of customer reliability (VCR) studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of unserved energy during a supply interruption. As outlined in our national STPIS, we will use VCR estimates at different stages of our annual s-factor calculation to:

- set the incentive rates for each reliability of supply parameter
- appropriately weight reliability of supply performance across different segments of the network.

[29] NER, clause 6.6.2(b)(2).
[30] NER, clause 6.6.2(b)(3)(ii).
[31] NER, clause 6.6.2(b)(1).
[32] NSW distributors, *Response to AER Preliminary F&A*, Aug 2012, p. 65.
[33] NER, clause 6.6.2(b)(3)(vi).

The VCR estimates in our national STPIS are taken from studies conducted for the Essential Services Commission of Victoria and the Essential Service Commission of South Australia.[34] The NSW distributors expressed concern about these VCR assumptions, noting they were undertaking their own VCR analysis and intended to submit their results to the AER.[35] Distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.

The AEMC recently conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.[36] AEMO is currently reviewing current approaches to estimating VCR and will propose new VCR estimates in March 2014.[37]

We intend to undertake a review of our national STPIS once these studies are complete. Any change to the STPIS would be subject to the distribution consultation procedures in the rules.[38] We consider there is insufficient time to conduct a comprehensive review of the STPIS before the NSW distributors submit proposals for the subsequent regulatory control period in May 2014. We therefore intend to apply the national STPIS in its current form.

1.3.3 Balanced incentives

We administer our incentive schemes within a regulatory control period to align distributor incentives with the NEO. In implementing the STPIS we need to be aware of both the operational integrity of the scheme itself and how it interacts with our other incentive schemes.

Distributor incentives under the STPIS

How we measure actual service performance and set performance targets can significantly impact how well the STPIS meets its stated objectives.

The rules require us to consider past performance of the distributor's network in developing and implementing the STPIS.[39] Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.[40] Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits the distributors' incentive to underperform in the final year of a regulatory control period to make future targets less onerous.

Our national STPIS limits variability in penalties and rewards caused by circumstances outside the distributors' control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance. The NSW distributors indicated they found the exclusion methodology in our national STPIS to be appropriate but sought the opportunity to propose amendments to the calculation methodology upon completion of their own analysis.[41]

Our national STPIS recognises differences across and within distribution networks. Measured performance and performance targets are specific to each segment of a distributor's network. The

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34 Charles River Associates, *Assessment of the Value of Consumer Reliability (VCR)*—Report prepared for VENCorp, Melbourne 2002; KPMG, *Consumer Preferences for Electricity Service Standards*, 2003.

35 NSW distributors, *Response to AER Preliminary F&A*, Aug 2012, p. 65–67.

36 AEMC, *Final Report: Review of the national framework for distribution reliability*, 27 September 2013.

37 AEMO, *Directions paper: Value of customer reliability*, 31 May 2013, p. 5.

38 NER, clause 6.6.2(c).

39 NER, clause 6.6.2(b)(3)(iii).

40 Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS.

41 NSW distributors, *Response to AER Preliminary F&A*, Aug 2012, p. 66.

NSW distributors submitted that they agree with our proposed approach to network segmentation subject to an exception relating to Endeavour Energy.[42] Endeavour Energy's distribution network contains only one long rural feeder, making SAIDI and SAIFI performance in the 'long rural' category extremely volatile. We consider that the financial impact of excluding this feeder is likely to be small, given our national STPIS weights incentive rates by the level of consumption in each feeder type.

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the rules or relevant distribution determination.[43] In NSW, the STPIS will interact with our expenditure and demand management incentive schemes.

The EBSS provides distributors with an incentive seek efficiencies in operating costs. The STPIS counterbalances this incentive by discouraging cost efficiencies that arise through reduced service performance for customers. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets. In accordance with the rules we must set incentive rates to offset any financial incentives the distributors may have to reduce costs at the expense of service levels.[44]

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[45] We are aware of recent amendments to the reliability planning standards in the NSW distribution licence conditions following a review by the AEMC,[46] coming into effect on 1 July 2014. We anticipate distributors' planned reliability improvements (within their capex proposals) will reflect this change, and STPIS performance targets to be set accordingly.

The CESS rewards distributors whose capex becomes more efficient. Since our performance targets will reflect planned reliability improvements, any incentive a distributor may have to reduce capex by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

The rules require us to consider the possible effects of the STPIS on the distributors' incentives to implement non-network alternatives to augmentation. The STPIS treats the reliability implications of network and non-network solutions symmetrically, neither encouraging nor discouraging non-network alternatives to augmentation.

We are aware of the perceived disincentive to implement demand-side alternatives to network augmentation created by reliability performance measures in the STPIS. Higher risk of failure to meet STPIS performance targets may act as a disincentive for non-network alternatives to network investment. One way to address this would be to exclude outages caused by non-network solutions from the calculation of actual performance. However, since network planning decisions are within the distributors' control, we consider this to be unnecessary.

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42 NSW distributors, *Response to AER Preliminary F&A*, Aug 2012, p. 66.
43 NER, clause 6.6.2(b)(3)(iv).
44 NER, clause 6.6.2(b)(3)(v).
45 Included in the distributor's approved forecast capex for the subsequent period.
46 AEMC, *Final Report: NSW Workstream – Review of distribution reliability outcomes and standards*, 31 August 2012.

2 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) aims to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices.

This section sets out our proposed approach and reasons on how we intend to apply the EBSS to NSW distributors in the transitional and subsequent periods.

2.1 AER's proposed approach

We propose to apply to NSW distributors:

- Version 1 of the EBSS for ACT/NSW distributors (the current EBSS)[47] in the 2014–15 transitional control period with modifications to align it with version 2 of the EBSS (the new EBSS). In summary, this will include:[48]
  - the formulae for calculating efficiency gains and losses
  - our approach to adjustments to forecast or actual opex when calculating carryover amounts
  - our approach to determining the carryover period.
- The new EBSS in the 2015–19 subsequent control period.

2.2 AER's assessment approach

The transitional rules set out that the EBSS which applied to the NSW distributors under the distribution determinations for their current regulatory control period, will apply to them for the transitional period subject to any modifications set out in the stage 2 F&A. These modifications can include non-application of the relevant scheme.[49]

The EBSS must provide for a fair sharing between distributors and network users of opex efficiency gains and efficiency losses.[50] We must also have regard to the following factors in developing and implementing the EBSS:[51]

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
- the need to provide distributors with a continuous incentive to reduce opex
- the desirability of both rewarding distributors for efficiency gains and penalising distributors for efficiency losses
- any incentives that distributors may have to capitalise expenditure

47 AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, 29 February 2008. (AER, *EBSS for ACT and NSW distributors*, Feb 2008).
48 AER, *Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013. (AER, *EBSS*, Nov 2013).
49 NER, clause 11.56.3(a)(4).
50 NER, clause 6.5.8(a).
51 NER, clause 6.5.8(c).

- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

2.3 Reasons for AER's proposed approach

The current EBSS applies to NSW distributors in the current regulatory control period.[52] As part of our Better Regulation program we consulted on and published the new EBSS, taking into account the requirements of the rules.

The new EBSS retains the same form as the current EBSS, and merges the distribution and transmission schemes. Changes in the new EBSS relate to the criteria for adjustments and exclusions under the scheme.[53] We also amended the scheme to provide flexibility to account for any adjustments made to base year opex to remove the impacts of one-off factors. The new EBSS also clarifies how we will determine the carryover period. These revisions affect how we will calculate carryover amounts for future regulatory control periods.[54]

In this section we set out why we propose to apply the new EBSS to the subsequent period. This informs our reasons for proposing to apply the new EBSS in the transitional period.

2.3.1 Reasons for applying the EBSS in the subsequent period

We propose to apply the new EBSS to the subsequent period. In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.[55] This reasoning extends to the factors we must have regard to in implementing the scheme.

The EBSS must provide for a fair sharing of efficiency gains and losses.[56] Under the scheme, distributors and consumers receive a benefit where a distributor reduces its costs during a regulatory control period and both bear some of any increase in costs.

Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.[57] The EBSS provides a continuous incentive for distributors to achieve opex efficiencies throughout the subsequent period. This is because the distributor receives carryover payments so it retains any efficiency gains or losses it makes within the regulatory period for the length of the carryover period. This is regardless of the year in which it makes the gain or loss.[58]

This continuous incentive to improve efficiency encourages efficient and timely opex throughout the regulatory control period, and reduces the incentive for a distributor to inflate opex in the expected base year. This provides an incentive for distributors to reveal their efficient opex which, in turn, allows us to better determine efficient opex forecasts for future regulatory control periods.

The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.[59] For instance the combined effect of our forecasting approach and the EBSS is that opex

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52 AER, *EBSS for ACT and NSW distributors*, Feb 2008.

53 We will no longer allow for specific exclusions such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth. We may also exclude categories of opex not forecast using a single year revealed cost approach from the scheme on an ex post basis if doing so better achieves the requirements of the rules.

54 AER, *EBSS*, Nov 2013.

55 AER, *EBSS*, Nov 2013; AER, *Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013. (AER, *EBSS Explanatory Statement*, Nov 2013).

56 NER, clause 6.5.8(a).

57 NER, clauses 6.5.8(c)(3) and 6.5.8(a).

58 NER, clause 6.5.8(c)(2).

59 NER, clause 6.5.8(c)(1).

efficiency gains or losses are shared approximately 30:70 between distributors and consumers. This means for a one dollar efficiency saving in opex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

Example 1 shows how the EBSS operates. It illustrates how the benefits of a permanent efficiency improvement are shared approximately 30:70 between a network service provider and consumers.

Example 1 How the EBSS operates

Assume that in the first regulatory period, a network service provider's forecast opex is $100 million per annum (p.a.).

Assume that during this period the service provider delivers opex equal to the forecast for the first three years. Then, in the fourth year of the regulatory period, the service provider implements a more efficient business practice for maintaining its assets. As a result, the service provider will be able to deliver opex at $95 million p.a. for the foreseeable future.

This efficiency improvement affects regulated revenues in two ways:

1. Through forecast opex. If we use the penultimate year of the regulatory period to forecast opex in the second regulatory period, the new forecast will be $95 million p.a. If the efficiency improvement is permanent, all else being equal, forecast opex will also be expected to be $95 million p.a. in future regulatory periods.
2. Through EBSS carryover amounts. The service provider receives additional carryover amounts so that it receives exactly six years of benefits from an efficiency improvement. Because the service provider has made an efficiency improvement of $5 million p.a. in Year 4, to ensure it receives exactly six years of benefits, it will receive annual EBSS carryover amounts of $5 million in the first four years (Years 6 to 9) of the second regulatory period.

As a result of these effects, the service provider will benefit from the efficiency improvement in Years 4 to 9. This is because the annual amount the service provider receives through the forecast opex and EBSS building blocks ($100 million) is more than what it pays for opex ($95 million) in each of these years.

Consumers benefit from Year 10 onwards after the EBSS carryover period has expired. This is because what consumers pay through the forecast opex and EBSS building blocks ($95 million) is lower from Year 10 onwards.

Table 2 provides a more detailed illustration of how the benefits are shared between service providers and consumers over time.

(Example 1 continued)

Table 2 Example of how the EBSS operates

			Regulatory period 1				Regulatory period 2				Future
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
Forecast (F_t)	100	100	100	100	100	95	95	95	95	95	95 p.a.
Actual (A_t)	100	100	100	95	95	95	95	95	95	95	95 p.a.
Underspend ($F_t – A_t = U_t$)	0	0	0	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t – U_{t-1}$)	0	0	0	5	0	0*	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					5	5	5	5	5		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (Ct)						**5**	**5**	**5**	**5**	**0**	**0 p.a.**
Benefits to NSP ($F_t – A_t + C_t$)	0	0	0	5	5	5	5	5	5	0	0 p.a.
Benefits to consumers ($F_1 – (F_t + C_t)$)	0	0	0	0	0	0	0	0	0	5	5 p.a.
Discounted benefits to NSP**	0	0	0	5	4.7	4.5	4.2	4.0	3.7	0	0
Discounted benefits to consumers**	0	0	0	0	0	0	0	0	0	3.5	58.8***

Notes: * At the time of forecasting opex for the second regulatory period we don't know actual opex for year 5. Consequently this is not reflected in forecast opex for the second period. That means an underspend in year 6 will reflect any efficiency gains made in both year 5 and year 6. To ensure the carryover rewards for year 6 only reflect incremental efficiency gains for that year we subtract the incremental efficiency gain in year 5 from the total underspend. In the example above, $I_6 = U_6 – (U_5 – U_4)$.

** Assumes a real discount rate of 6 per cent.

*** As a result of the efficiency improvement, forecast opex is $5 million p.a. lower in nominal terms. The estimate of $58.7m is the net present value of $5 million p.a. delivered to consumers annually from year 11 onwards.

Table 3 sums the discounted benefits to NSPs and consumers from the bottom two rows of Table 2. As illustrated below, the benefits of the efficiency improvement are shared approximately 30:70 in perpetuity between the service provider and consumers.

Table 3 Sharing of efficiency gains—Year 4 forecasting approach, with EBSS

	NPV of benefits of efficiency improvement[1]	Percentage of total benefits
Benefits to service provider	$26.1 million	30 per cent
Benefits to consumers	$62.3 million	70 per cent
Total	$88.3 million	100 per cent

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.[60] Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. The CESS is a symmetric capex scheme with a 30 per cent incentive power. This is consistent with the incentive power for opex when we use an unadjusted base year approach in combination with an EBSS. During the subsequent period when the CESS and EBSS are applied, incentives will be relatively balanced, and distributors should not have an incentive to favour opex over capex or vice versa. The CESS is discussed further in attachment 3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives.[61] Expenditure on non-network alternatives generally takes the form of opex rather than capex. Successful non-network alternatives should result in the distributor spending less on capex than it otherwise would have. Non-network alternatives and demand management incentives are discussed further in attachment 4.

Both the CESS and EBSS will apply in the subsequent period. As a result a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way, the distributor will receive a net reward for implementing the non-network alternative.[62] This is because the rewards and penalties under the EBSS and CESS are balanced and symmetric. In the past where the EBSS operated without a CESS, we excluded expenditure on non-network alternatives when calculating rewards and penalties under the scheme. This was because distributors may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.[63]

2.3.2 Reasons for applying the EBSS in the transitional period

Under the transitional rules we may:[64]

- apply the current EBSS in the transitional period
- apply the current EBSS with modifications
- not apply the EBSS.

We propose to apply the current EBSS, modified to align it with the new EBSS, in the transitional period. This means that we are effectively applying the new scheme to the transitional year. We have taken this approach because:

- We consider it is preferable to apply the new scheme consistently to all network service providers as soon as practicable. The new EBSS and accompanying explanatory statement were published on 29 November 2013.[65] In developing the new scheme we had regard to the criteria in the rules and took into account stakeholder views. We developed the new EBSS for all network service providers with the intent of applying a nationally consistent approach to incentives for opex performance.

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[60] NER, clause 6.5.8(c)(4).
[61] NER, clause 6.5.8(c)(5).
[62] When the distributor spends more on opex it receives a 30 per cent penalty under the EBSS. However, when there is a corresponding decrease in capex the distributor receives a 30 per cent reward under the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward.
[63] Without a CESS the reward for capex declines over the regulatory period. If an increase in opex corresponded with a decrease in capex, the off-setting benefit of the decrease in capex depends on the year in which it occurs.
[64] NER, clause 11.56.3(a)(4).
[65] AER, *EBSS*, Nov 2013; AER, *EBSS Explanatory Statement*, Nov 2013.

- It is preferable for the same scheme to apply for the entirety of the regulatory control period. As discussed, the new EBSS revises the approach to adjustments and exclusions. Therefore, applying the current EBSS in the transitional period followed by the new EBSS for the subsequent period could result in exclusions being permitted in the transitional period but not the remainder of the period, and an inconsistent approach to adjustments. Applying different schemes within the same period also adds administrative complexity.

In the remainder of this section we discuss why we consider the EBSS should continue to apply in the transitional year.

If we apply the EBSS in the transitional period, the same benefits associated with the scheme will apply as discussed in section 2.3.1. For instance, distributors will still face continuous incentives to achieve opex efficiencies. This incentivises distributors to reveal their efficient opex which, in turn, allows us to better determine efficient opex forecasts for future regulatory control periods.

Under the transitional rules, we will not make a determination on opex allowances for the transitional period until our determination for the subsequent period. This means we will not finalise distributors' opex allowances for the transitional period until towards the end of 2014–15. This poses difficulties for distributors and does create some significant uncertainties.

We considered how this might impact the operation of the EBSS and carried out modelling for a range of potential scenarios. These scenarios included continuing the EBSS in the transitional period where final opex targets are uncertain, not continuing it or suspending its operation, and comparing situations where there are potential efficiency gains and potential efficiency losses.

Our analysis indicates that not continuing the scheme would create distorted incentives that are likely to be significantly greater than the effects of continuing the scheme with uncertain targets in the transitional period. We discussed these issues with stakeholders, including the distributors. Stakeholders agreed that, in the circumstances, the preferable outcome is for the EBSS to apply.

Operation of the EBSS when distributors do not have final opex targets

Under the EBSS, distributors receive the additional benefits of an efficiency gain for a fixed period (e.g. six years for a recurrent efficiency gain). The financial incentives a business faces are based on the additional expected reward that business would receive for an efficiency gain. That is, how much a distributor gets to keep of every extra dollar it is able to save continues to operate as an incentive. Under the EBSS, the proportion of benefits of an efficiency gain retained by a distributor does not change based on the opex target, so there is still a continuing incentive to make efficiency gains.

While distributors may not know their final opex targets until our final determination is made in the latter part of the transitional period, our draft determination will be released in November 2014. This is five months after the start of the transitional period and will contain a draft opex allowance. This will provide a degree of guidance for distributors in the earlier part of the transitional period.

In addition, we use controllable opex to measure efficiency gains or losses under the EBSS and this tends to be largely recurrent and predictable. Also, an efficiency gain or loss made in the first year of the regulatory period (i.e. the transitional period) only inputs into the carryover amount a distributor receives in the first year of the following period as the carryover period and the regulatory period overlap almost entirely. This is compared to efficiency gains or losses made in later years of the regulatory period which input into carryover amounts for multiple years in the following period.[66]

Not applying the EBSS affects other regulatory years

The EBSS operates on an incremental basis, and performance in one year is related to performance in the previous year. Not applying the EBSS in the transitional period could disrupt the incentives provided by the EBSS to make efficiency gains in other years. Specifically:

- The measurement of efficiency gains under the EBSS is not only a function of how a distributor performed against its opex targets in a particular year. That is, the scheme does not only reward efficiency gains in absolute terms. We calculate efficiency gains on an incremental basis and it is the incremental gain or loss that is rewarded or penalised under the scheme. That is, efficiency gains relate to how a distributor performs in a given year compared to how it performed in the previous year.[67]
- Consider the 2014–19 regulatory period, where the transitional period is 'Year 1'. Even if we do not apply the EBSS in Year 1 a distributor's performance in that year influences its incremental performance in Year 2 (2015–16). In turn its performance in Year 2 then shapes how we measure its performance in Year 3 (2016–17), and so on.

Impacts of not applying the EBSS on distributors and consumers

Appendix A sets out the impacts on distributors and consumers if we do not apply the EBSS in the transitional period.

Not applying the EBSS to the transitional period alters the carryover payments a distributor receives. In turn, this alters the sharing of efficiency gains and losses between distributors and consumers. This may have undesirable outcomes for distributors or consumers, inconsistent with the factors we must have regard to in developing and implementing the EBSS. NSW distributors agreed that the EBSS could continue to apply in the transitional period, and that not applying the scheme could result in unwanted outcomes.[68] These potential perverse outcomes are explained as follows:

- We find that not applying the scheme is unlikely to have a neutral impact on distributors or consumers. In some circumstances, a distributor may receive an additional benefit if we do not apply the EBSS that it otherwise would not have if we applied the scheme. In turn, this benefit comes at the expense of a detriment to consumers. In other circumstances, a distributor may experience detriment if we do not apply the EBSS that it would not have if we applied the scheme. In turn, this detriment means consumers benefit where they otherwise would not have. We do not consider there is any reason why distributors should receive additional benefits, while consumers suffer detriment, and vice-versa.[69]

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66 A distributor retains an efficiency gain or bears an efficiency loss for the length of the carryover period. The carryover period is five years in this case. For its performance in the transitional period a distributor may make an efficiency gain (or loss) in the transitional period. It would retain the gain (or incur the loss) for the remainder of the regulatory period—four more years. Then it would receive an EBSS carryover amount in the first year of the following period—completing the five year carryover period.

67 Distributors are not simply rewarded or penalised simply for under or over spending on opex in a given year. Suppose a distributor spends as forecast in year one, then underspends in year two, then underspends again but by exactly the same amount in year three. It has made an efficiency gain in year two because it performed better than in year one. But, it has not made an efficiency gain in year three, even though it is still underspending, because it has not performed any better than in year two.

68 AER, Meeting with NSW distributors, 7 November 2013.

69 In implementing the EBSS we must have regard to ensuring that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme, NER, clause 6.5.8(c)(1).

- If we did not apply the EBSS to the transitional period we find that, depending on the circumstances, a distributor could retain an efficiency gain or loss made in the transitional year for longer or less than the carryover period. This would disrupt the continuous incentive the scheme otherwise provides. This is because the continuous incentive depends on a distributor retaining gains or losses for the length of the carryover period.[70]
- In other circumstances, if we do not apply the EBSS we find a distributor could be better off after an efficiency loss in the transitional period, compared to if we applied the scheme. Conversely, a distributor could be worse off after an efficiency gain compared to if we applied the scheme. This is contrary to the rules which provide for the desirability of rewarding distributors for efficiency gains and penalising distributors for efficiency losses.[71]
- The impact on carryover payments alters the sharing of efficiency gains and losses between distributors and consumers. As discussed, the implicit power of the incentive under the EBSS is approximately 30 per cent. In developing the new EBSS we concluded this was suitable and provides for a fair sharing of efficiency gains and losses between distributors and consumers. If we did not apply the EBSS in the transitional period, the power of the incentive would change, and efficiency gains or losses would be shared differently to how they would be if we applied the scheme. We do not see a compelling reason why the power of the incentive in the transitional year should be different to 30 per cent.

Capitalising expenditure

In implementing the EBSS in the transitional period we must have regard to any incentives distributors may have to capitalise expenditure.[72] The incentive for capitalising opex is related to the interaction between the EBSS and CESS. During the transitional period we cannot apply the CESS.[73]

However, the incentive to incur efficient capex is highest in the first year of the regulatory period.[74] Without the CESS a distributor could bear more than 30 per cent of the cost of a capex overspend in the first year of the regulatory period.[75] Therefore the incentive to capitalise opex in the transitional period may be relatively weaker when the EBSS applies but not the CESS.

Non-network alternatives

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives.[76] When the CESS and EBSS both apply a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. During the transitional period we cannot apply the CESS.[77] In addition, under the new EBSS we will no longer allow for specific exclusions such as non-network alternatives.[78]

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70 NER, clause 6.5.8(c)(2).
71 NER, clause 6.5.8(c)(3).
72 NER, clause 6.5.8(c)(4).
73 NER, clause 11.56.3(a).
74 Distributors only retain the benefits (or bear the costs) of any underspend (overspend) until the end of the regulatory control period. In year one, any benefit/penalty from an underspend/overspend will last for four years before the RAB is updated for actual capex. In year two, any benefit/penalty from an underspend/overspend will last for three years, and so on. In year five the benefit/penalty will be approximately zero. Hence, the power of the incentive declines over the regulatory period.
75 Depending on the life of the asset, assuming the regulatory WACC and the distributor's true WACC are both 8 per cent, and using actual depreciation; see AER, *Expenditure incentives guidelines for electricity network service providers—Issues paper*, 20 March 2013, pp. 9–11.
76 NER, clause 6.5.8(c)(5).
77 NER, clause 11.56.3(a).
78 AER, *EBSS*, Nov 2013, p. 7.

However, this may not create a significant disincentive to implementing non-network alternatives because:

- As discussed above, without a CESS the distributor's reward for reducing capex can be higher than 30 per cent in the first year of the regulatory period. The disincentive to increase opex from the EBSS remains set at 30 per cent. Therefore the incentive to implement a non-network alternative which reduces capex and increases opex in the transitional period is likely to be the same or greater than it would have been if both the CESS and EBSS applied.
- Distributors must include spending on non-network alternatives in developing their expenditure forecasts, and efficient spending for non-network alternatives would be included in a distributor's allowance. The rewards and penalties under the CESS and EBSS would only apply to non-network alternatives implemented during the period that were not accounted for in the distributor's expenditure allowance. The transitional period is very close to the time when we make our determination, to the point that it overlaps. NSW distributors should have a fairly certain idea of non-network alternatives they intend to implement that may reduce capex and increase opex in the transitional period. It seems likely such non-network alternatives will be considered at the determination for inclusion in expenditure allowances.

3 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. This attachment sets out our proposed approach and reasons for how we intend to apply the CESS to NSW distributors in the transitional and subsequent regulatory control periods.

The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between distributors and network users.

The CESS works as follows:

- We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the distributor's share of the underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of the underspends or overspends.[79] We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of an underspend or overspend, while consumers retain 70 per cent of the underspend on overspend. This means that for a one dollar saving in capex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

3.1 AER's proposed approach

We propose to apply to NSW distributors:

- no CESS in the transitional regulatory control period
- the CESS as set out in our capex incentives guideline in the subsequent regulatory control period.[80]

3.2 AER's assessment approach

The transitional rules specify that no CESS applies to the NSW distributors for the transitional regulatory control period.[81]

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:[82]

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[79] We calculate benefits as the benefits to the distributor of financing the underspend since the amount of the underspend can be put to some other income generating use during the period. Losses are similarly calculated as the financing cost to the distributor of the overspend.

[80] AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9. (AER, *Capex incentive guideline*, Nov 2013).

[81] NER, clause 11.56.3(a)(3).

- make that decision in a manner that contributes to the capex incentive objective[83]
- consider the CESS principles,[84] capex objectives,[85] other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

Broadly speaking, the capex incentive objective is to ensure that only capex that meets the capex criteria enters the RAB used to set prices. Therefore, consumers only fund capex that is efficient and prudent.

3.3 Reasons for AER's proposed approach

We cannot apply the CESS to NSW distributors in the transitional regulatory control period.[86] But we propose to apply the CESS to distributors in the subsequent regulatory control period as we consider this will contribute to the capex incentive objective.

NSW distributors are not currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.[87] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[88] We are also proposing to apply forecast depreciation, which we discuss further in attachment 6.

In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the EBSS, STPIS, and DMIS—which the distributors will be subject to in the subsequent control period.

For capex, the sharing of underspends and overspends happens at the end of each regulatory period when we update a distributor's RAB to include new capex. If a distributor spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the distributor had spent the full amount of the capex forecast. This leads to lower prices in the future.

Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.[89] Because of this a distributor may choose to spend capex earlier, or on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

With the CESS a distributor faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide distributors with an ex ante incentive to spend only efficient capex. Distributors that make efficiency gains will be rewarded through the CESS. Conversely, distributors that make efficiency losses will be penalised through the CESS. In this way, distributors will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more likely to reflect the capex criteria. In particular, if a

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82 NER, clause 6.5.8A(e).
83 NER, clause 6.4A(a); the capex criteria are set out in clause 6.5.7(c) of the NER.
84 NER, clause 6.5.8A(c).
85 NER, clause 6.5.7(a).
86 NER, clause 11.56.3(a)(3).
87 AER, *Capex incentive guideline*, Nov 2013, pp. 5–9.
88 AER, *Capex incentive guideline*, Nov 2013, pp. 10–11.
89 As the end of the regulatory period approaches, the time available for the distributor to retain any savings gets shorter. So the earlier a distributor incurs an underspend in the regulatory period, the greater its reward will be.

distributor is subject to the CESS, its capex is more likely to be efficient and to reflect the costs of a prudent distributor.

When the CESS, EBSS and STPIS apply to distributors then incentives for opex, capex and service are balanced. This encourages distributors to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

4 Demand management incentive scheme

This attachment sets out our proposed approach and reasons for applying a demand management incentive scheme (DMIS) to the NSW distributors in the next regulatory control period.[90]

The usage patterns of geographically dispersed consumers determine how electrical power flows through a distribution network. Since consumers use energy in different ways, different network elements reach maximum utilisation levels at different times. Distributors have historically planned their network investment to provide sufficient capacity for these situations. As peak demand periods are typically brief and infrequent, network infrastructure often operates with significant redundant capacity.

This underutilisation means that augmentation of network capacity may not always be the most efficient means of catering for increasing peak demand. Demand management refers to any effort to lower or shift the demand for standard control services.[91] Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.[92] To meet this requirement, and motivated by the need to improve NSW distributors' capability in the demand management area, we implemented a DMIS in our distribution determinations for the current regulatory period.

The current DMIS for NSW distributors includes two components—the demand management innovation allowance (DMIA)[93] and the D-factor.[94]

The DMIA is a capped allowance for distributors to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A provides for an innovation allowance to be incorporated into each distributor's revenue allowance for opex each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA[95] in the previous year, which we then assess against specific criteria.[96]

- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A. In the current regulatory control period, NSW distributors are subject to a weighted average price cap (WAPC) form of control. Under this control mechanism, if a demand management project results in a fall in demand for direct control services, the distributor's recoverable revenues will fall as prices are fixed. For this reason, foregone revenue is recoverable under Part B of the DMIA.

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90 The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS include embedded generation. We consider embedded generation to be one means of demand management, as it typically reduces demand for power drawn from a distribution network.

91 For example, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for power drawn from the distribution network.

92 NER, clause 6.6.3(a).

93 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations—Demand management innovation allowance scheme*, 28 November 2008. (AER, *DMIA for ACT and NSW distributors*, Nov 2008).

94 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations—D-factor scheme*, 29 February 2008. (AER, *D-factor for ACT and NSW distributors*, Nov 2008).

95 The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009–14 period or under the D-factor scheme.

96 AER, *DMIA for ACT and NSW distributors*, Nov 2008, pp. 4–5.

Under the scheme, we return any underspend against the allowance to customers and compensate distributors for approved foregone revenue, once we know their approved DMIA expenditure for each year of the current period. We will implement this as an adjustment to each distributor's innovation allowance for the second year of the following regulatory control period.

Our current NSW DMIS inherited IPART's D-factor scheme,[97] which also acts as a counter balance to distributors' disincentive to implement demand management under the WAPC form of control. The D-factor offers compensation for both the costs and forgone revenue incurred from demand management projects for which the distributor can demonstrate a resultant reduction in both capex and demand.

4.1 AER's proposed approach

We propose to continue applying the DMIA but discontinue the D-Factor scheme for NSW distributors from the transitional regulatory control period onwards.

The change in control mechanism to a revenue cap in the next regulatory control period removes the need for the foregone revenue mechanisms currently compensating distributors under the WAPC.

We acknowledge the need to reform the existing demand management incentive arrangements in NSW. The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. We intend to develop and implement a new DMIS for the subsequent regulatory control period, depending on the progress of the rule change process.

4.1.1 DMIA

We propose to apply Part A of the DMIA in both the transitional and subsequent periods. However, we propose to discontinue the Part B foregone revenue component of the DMIA due to the move to a revenue cap.

The current innovation allowance amounts will continue in the transitional year. In their submission on our 2012 Preliminary Framework and Approach, the NSW distributors argued for an increase in DMIA funding.[98] We will consider this issue during the reset process for the subsequent period.

4.1.2 D-factor

We propose to discontinue the D-factor in the transitional or subsequent regulatory control periods due to the move to a revenue cap.

However, as the D-factor operates on a two-year lag, distributors will be able to recover the costs and foregone revenues of applicable demand management projects in the current regulatory control period in the next period.

4.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a DMIS for the NSW distributors.[99] These are:

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97 From IPART's NSW distribution determinations for the 2004–09 regulatory control period.
98 NSW distributors, *Response to AER Preliminary F&A*, Aug 2012, p. 70.

- Benefits to consumers
  - the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
  - the willingness of customers or to pay for increases in costs resulting from implementing DMIS.
- Balanced incentives
  - the effect of a particular control mechanism (i.e. price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
  - the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
  - the extent the distributor is able to offer efficient pricing structures
  - the possible interactions between DMIS and other incentive schemes.

4.3 Reasons for AER's proposed approach

This section outlines the reasons for our proposed application of the DMIS for NSW distributors in the transitional and subsequent regulatory control periods.

4.3.1 Benefits to consumers

Customers ultimately fund the DMIA adjustment to a distributor's annual revenue each year. As such, we are mindful of the potential impact of the DMIS on consumers. Under the rules, we must consider customers' willingness to pay for any higher costs resulting from the scheme so benefits to consumers are sufficient to warrant any penalty or reward.

We assess projects for which distributor's apply for DMIA funding under a specific set of criteria.[100] The DMIA aims to enhance distributors' knowledge and experience with non-network alternatives, therefore improving the consideration of demand management in future decision making. This means the benefits of any higher consumer prices directly caused by the scheme may not be revealed until later periods. Benefits include more efficient utilisation of existing network infrastructure and the deferral of network augmentation expenditure.

We expect the potential long-term efficiency gains resulting from improved distributor capability to undertake demand management initiatives to outweigh short-term price increases. Price impacts will be minimal as adjustments to annual revenue for the DMIA are capped at modest levels and the allowances are provided on a 'use it or lose it' basis.

While studies[101] to date indicate that customers are supportive of demand management initiatives in principle, we know little about their willingness to pay. We consider our proposed application of the DMIS to be suitable in light of this limited information, given that the modest level of the DMIA means potential price increases will be minimal.

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[99] NER, clause 6.6.3(b).

[100] AER, *DMIA for ACT and NSW distributors*, 28 November 2008, pp. 4–5.

[101] For example, Oakley Greenwood, *Valuing reliability in the national electricity market, final report*, March 2011. This report was prepared for AEMO.

4.3.2 Balanced incentives

We administer our incentive schemes within a regulatory control period to align distributor incentives with the NEO. In implementing the DMIS, we need to be aware of how the scheme interacts within a distributor's overall incentive environment.

Control mechanism and service classification

The rules require we have regard for how a distributor's control mechanism influences its incentives to adopt or implement efficient non-network alternatives to network augmentation.[102] The change from a WAPC to a revenue cap removes NSW distributors' disincentive for demand management under the current control mechanism. We therefore consider it appropriate to discontinue the recovery of foregone revenue through Part B of the DMIA and the D-factor scheme in NSW.

We are also required to consider the effect of service classification on a distributor's incentive to adopt or implement efficient embedded generator connections.[103] We consider our proposed application of the DMIS meets this requirement as NSW distributors will be under a revenue cap in the transitional and subsequent regulatory control periods. The disincentives for demand management under the current WAPC control mechanism will no longer be relevant.

Distributor's ability to offer efficient pricing structures

The rules also require we consider the extent to which the distributor is able to offer efficient pricing structures in our design and implementation of a DMIS.[104] Efficient pricing structures reflect the true costs of supplying electricity at a particular part of the network at any given time. These tariff structures would price electricity highest during peak demand periods, reflecting the high costs of transporting energy when a network utilisation is at its highest. This price signal would discourage grid electricity usage at these times, lowering peak demand and adjusting network utilisation downwards.

At present, NSW distributors' ability to use efficient price signals is constrained by the low penetration of the required metering and other enabling technologies. We consider that efficient pricing, enabled by 'smarter' grid technologies will have a significant impact on distribution network utilisation in the future. The DMIA incentivises distributors to trial measures that will assist the transition of networks towards this goal.

Interaction with our other incentive schemes

The DMIA intends to encourage distributors to investigate and implement innovative DM strategies, regardless of their potential effectiveness. In developing and implementing the DMIS in NSW, we must consider how it could potentially interact with our other incentive schemes.[105] Neither our expenditure incentive schemes (EBSS and CESS) nor STPIS intend to discourage a distributor from using its DMIA allowance.

Although the innovation allowance is incorporated into a distributor's opex allowance each year, we may exclude the DMIA from actual and forecast opex when calculating carryover payments for the EBSS.[106] Any potential substitution between opex and capex resulting from projects approved under

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102 NER, clause 6.6.3(b)(2).
103 NER, clause 6.6.3(b)(6).
104 NER, clause 6.6.3(b)(3).
105 NER, clause 6.6.3(b)(4).
106 Under the EBSS we can exclude any categories of opex not forecast using a single year revealed cost approach where it would better achieve the requirements (of the EBSS) under cl. 6.5.8 of the NER. DMIA projects are excluded from forecast opex so not considered to be forecast using a single year revealed cost approach. AER, *EBSS*, Nov 2013.

the DMIA will be incentive-neutral as our proposed EBSS and CESS provide balanced incentives for opex and capex savings.

5 Expenditure forecast assessment guideline

This attachment sets out our intention to apply our expenditure forecast assessment guideline (guideline)[107] including the information requirements to the NSW distributors for the 2014–19 regulatory control period. We propose applying the guideline as it sets out our new expenditure assessment approach developed and consulted upon during the Better Regulation program. The guideline outlines for distributors and interested stakeholders the types of assessments we will do to determine efficient expenditure allowances, and the information we require from the distributors to do so.

We were required to develop the guideline under the rules.[108] The guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. The rules required the NSW distributors to advise us by 30 November 2013 of the methodology they propose to use to prepare forecasts.[109] In the F&A we must advise whether we will deviate from the guideline.[110] This will provide clarity to the distributors on how we will apply the guideline and the information they should include in their regulatory proposals.

The guideline contains a suite of assessment/analytical tools and techniques to assist our review of regulatory proposals by network service providers. We intend to apply all the assessment tools set out in the guideline. The tool kit consists of:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.[111]

We developed the guideline to apply broadly to all electricity transmission and distribution businesses. However, some customisation of the data requirements contained in the guideline might be required. This is particularly in regard to services that we classify in different ways and are subject to different forms of control. For example, nationally consistent data for benchmarking and trend assessment of public lighting costs may not be sufficient to scrutinise the particular pricing models employed by particular distributors. The guideline itself does not explicitly require these distributors to submit or justify inputs to these models and we may request specific data to assist us with this analysis. We expect that these data customisation issues would be addressed through the Regulatory Information Notice that we will issue to the NSW distributors for the next regulatory control period.

107 We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.
108 NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4.
109 NER, clauses 6.8.1A(b)(1) and 11.60.3(c).
110 NER, clause 6.8.1(b)(2)(viii).
111 AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

6 Depreciation

As part of the roll forward methodology, when the RAB is updated from forecast capex to actual capex at the end of a regulatory control period, it is also adjusted for depreciation. This attachment sets out our proposed approach to calculating depreciation when the RAB is rolled forward to the commencement of the 2019–24 regulatory control period.

The depreciation we use to roll forward the RAB can be based on either:

- Actual capex incurred during the regulatory control period (actual depreciation). We roll forward the RAB based on actual capex less the depreciation on the actual capex incurred by the distributor; or

- The capex allowance forecast at the start of the regulatory control period (forecast depreciation). We roll forward the RAB based on actual capex less the depreciation on the forecast capex approved for the regulatory control period.

The choice of depreciation approach is one part of the overall capex incentive framework.

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.[112] In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that the RAB will increase by a lesser amount than if forecast depreciation were used. So, the distributor will earn less revenue into the future (i.e. it will bear more of the cost of the overspend into the future) than if forecast depreciation had been used to roll forward the RAB.

- If there is a capex underspend, actual depreciation will be lower than forecast depreciation. This means that the RAB will increase by a greater amount than if forecast depreciation were used. Hence, the distributor will earn greater revenue into the future (i.e. it will retain more of the benefit of an underspend into the future) than if forecast depreciation had been used to roll forward the RAB.

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for shorter lived assets compared to longer lived assets. Forecast depreciation, on the other hand, leads to the same incentive for all assets.

6.1 AER's proposed approach

We propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2019–24 regulatory control period for NSW distributors. We consider this approach will provide sufficient incentives for the distributors to achieve capex efficiency gains over the 2014–19 regulatory control period.

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112 AER, *Capex incentive guideline*, Nov 2013, pp.10–11.

6.2 AER's assessment approach

The transitional rules specify that the depreciation approach for establishing the RAB at the commencement of the transitional control period and subsequent control period is to be that which was decided in the determination for the current regulatory control period.[113]

We must decide at our determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.[114]

We are required to set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.[115] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[116]

- any other incentives the service provider has to undertake efficient capex
- substitution possibilities between assets with different lives
- the extent of overspending and inefficient overspending relative to the allowed forecast
- the capex incentive guideline
- the capital expenditure factors.

6.3 Reasons for AER's proposed approach

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2019–24 regulatory control period.

We had regard to the relevant factors in the rules in developing the approach to choosing depreciation set out in our capex incentives guideline.[117]

Our approach is to apply forecast depreciation except where:

- there is no CESS in place and therefore the power of the capex incentive may need to be strengthened, or
- a distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher powered incentive.

In making our decision on whether to use actual depreciation in either of these circumstances we will consider:

- the substitutability between capex and opex and the balance of incentives between these
- the balance of incentives with service
- the substitutability of assets of different asset lives.

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113 NER, clause 11.56.3(a)(13).
114 NER, clause S6.2.2B.
115 NER, clause 6.4A(b)(3).
116 NER, clause S6.2.2B.
117 AER, *Capex incentive guideline*, Nov 2013, pp. 10–11.

We have chosen forecast depreciation as our default approach because, in combination with the CESS, it will provide a 30 per cent reward for capex underspends and 30 per cent penalty for capex overspends, which is consistent for all asset classes. In developing our capex incentives guideline, we considered this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.

NSW distributors are not currently subject to a CESS but we propose to apply the CESS in the subsequent regulatory control period. We discuss this further in attachment 3.

For NSW distributors, at this stage, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.[118] Therefore, we do not see the need to apply actual depreciation at this time.

[118] Our ex post capex measures are set out in the capex incentives guideline (AER, C*apex incentive guideline*, Nov 2013, pp. 13–19); the guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective (AER *Capex incentive guideline*, Nov 2013, pp. 20–21).

7 Prices for alternative control services in 2014–15

Changes made to the rules in 2012 delayed the commencement of the 2014–19 review of NSW electricity distribution prices. To accommodate this delay, the AEMC introduced a number of transitional provisions to the rules including the need for placeholder prices in 2014–15. To a large extent, the approach set out in the rules to alternative control services prices in 2014–15 means that for customers there will be few changes in this transitional year. Alternative control services prices will typically increase by CPI and no substantive changes to current alternative control services pricing approaches will be made in the transitional year.

These placeholder prices in 2014–15 may be subject to a true-up once the review is completed. A true-up would involve making adjustments to prices in 2015–16 and subsequent years to account for differences between the placeholder prices adopted for 2014–15 and those prices determined once our full assessment has been completed. Any true-up will be conducted in accordance with the rules.

In its final determination, the AEMC stated:[119]

> To the extent that it is relevant, a separate true-up mechanism will also be used for the NSW DNSPs and ActewAGL to account for any differences between the alternative control service prices applying in the transitional regulatory period and the prices established through the full determination process.

We have held a number of discussions with the NSW distributors regarding whether such a true-up for these services will be necessary and how a true-up would work in practice. AER staff wrote to the NSW distributors in December 2013 to assist in clarifying the approach that might be taken to alternative control services prices in 2014–15 (see appendix B).[120] The purpose of the letter was to assist the distributors adopt an approach to alternative control services prices in 2014–15 that complies with the rules and minimises significant changes that could impact on consumers in the transitional year.

In response, the NSW distributors requested that we specify in this F&A how a true-up of prices will be made. The distributors also set out their preliminary views on how a true-up mechanism could work. As stated in the AEMC's determination, to the extent that it is relevant, a true-up mechanism could be used to account for any differences between the alternative control services prices applying in the transitional period and those established in the full determination process. This true-up mechanism may be similar to the mechanisms proposed by the distributors. However, given that we are yet to see how the distributors intend to treat alternative control services pricing in their transitional proposals, we would prefer not to prejudice whether, and if so, how alternative control services prices are to be trued-up. For this reason, we will not be specifying the exact manner in which alternative control services prices may be adjusted in this F&A.

The Stage 1 F&A indicated that metering services and monopoly and miscellaneous services would be reclassified as alternative control services in the next regulatory control period. For these services, there will be no change to the current pricing approach in 2014–15 because the rules require the approach to cost allocation to be retained in the transitional year. We will examine the options for a true-up of these services as part of our regulatory review and provide reasons for the approach that is eventually to be adopted in our determination.

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119 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 241.

120 The December 2013 letter did not contain reference to prices for Emergency Recoverable Works (ERW). ERW should have been mentioned in the same group as monopoly and miscellaneous services (Group 3). Our preferred approach to the treatment of Group 3 ACS services is set out in appendix B.

A Appendix—not applying the EBSS in the transitional period

To not apply the EBSS in the transitional period we could:

- option 1—set the efficiency gain in the transitional period to zero
- option 2—assume the distributor spends exactly its allowance in the transitional period.

Both option 1 and option 2 have potentially undesirable outcomes for both distributors and consumers compared to applying the EBSS as normal.

Take the example of the 2014–19 regulatory period, with the transitional period as Year 1. Under the scheme a distributor retains an efficiency gain or bears an efficiency loss for the length of the carryover period. The carryover period is five years in this case. For its performance in the transitional period a distributor may make an efficiency gain (or loss) in Year 1. It would retain the gain (or incur the loss) for the remainder of the regulatory period—four more years. Then it would receive an EBSS carryover amount in the first year of the following period—completing the five year carryover period. The efficiency gain or loss is then shared with consumers through prices in the following year.

We find that under option 1:

- For a recurrent efficiency gain or loss made in the transitional period, a distributor would retain the gain (or bear the loss) for one year less, and it would be shared with consumers one year sooner, compared to if we applied the EBSS.
- For a one-off efficiency loss made in the transitional period, a distributor would receive a positive carryover payment (a reward) instead of a negative payment (a penalty) compared to if we applied the EBSS. Vice-versa for a one-off efficiency gain. This would not provide the distributor with an incentive to reduce operating expenditure.[121] It would also not penalise the distributor for the one-off efficiency loss.[122]

Under option 2:

- For a recurrent efficiency gain or loss made in the transitional period, the distributor would retain a recurrent efficiency gain (or bear a loss) for one extra year, and sharing with consumers would be delayed by one year, compared to if we applied the EBSS.
- For a one-off efficiency gain or loss made in the transitional year, a distributor would not receive any carryover payment and the gain or loss would not be shared with consumers.[123]

If we do not apply the EBSS using either option 1 or option 2, this affects carryover payments. This, in turn, alters the sharing of an efficiency gain or loss made in the transitional period between the distributor and consumers. This affects the power of the incentive a distributor faces to make efficiency improvements in that year. The share of efficiency gains and losses under these two options is shown in Table 4.

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121 NER, clause 6.5.8(c)(2).
122 NER, clause 6.5.8(c)(3).
123 NER, clause 6.5.8(a).

Table 4 Sharing efficiency losses in the transitional period

	EBSS in the transitional period	Percentage of total loss
Recurrent efficiency loss in transitional period		
Distributor	Apply EBSS	30 per cent
	Not apply with option 1	25 per cent
	Not apply with Option 2	33 per cent
Consumers	Apply EBSS	70 per cent
	Not apply with option 1	75 per cent
	Not apply with Option 2	67 per cent
Non-recurrent efficiency loss in transitional period		
Distributor	Apply EBSS	30 per cent
	Not apply with option 1	-45 per cent
	Not apply with Option 2	100 per cent
Consumers	Apply EBSS	70 per cent
	Not apply with option 1	145 per cent
	Not apply with Option 2	0 per cent

B Appendix—letter to NSW distributors clarifying alternative control services prices in 2014–15

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11 December 2013

Mr Michael Martinson
Group Manager Regulation
Networks NSW
51 Huntington Drive
HUNTINGWOOD NSW 2148

Dear Mike

Alterative Control Service (ACS) prices for the transitional regulatory year

At our meeting last week we discussed the topic of how ACS prices should be set in the transitional regulatory year. At the conclusion of the meeting you asked if the AER could provide you with a note setting out our initial thoughts. This letter sets out the views of AER staff on this topic. These views have not been endorsed by the AER and are provided by staff to assist you in formulating your views.

We recognise that the application of the transitional rules to ACS pricing is a complex issue and one where the author of the transitional rules may not have been able to consider all the possible scenarios that have arisen. Our preferred approach, as set out below, seeks to comply with the rules and minimise significant changes that would impact on consumers in the transitional year. The approach also reflects, where possible, our proposed approach for the subsequent regulatory control period.

Several key provisions of the rules relating to ACS prices in the transitional year are set out in clause 11.56.3 of the *National Electricity Rules* (NER). In particular:

- Subclause 11.56.3(j) of the NER suggests prices for ACS services may only be increased by CPI in the transitional year. (I understand that your staff may have a different view on the meaning of this subclause).
- Subclause 11.56.3(i) suggests that the cost allocations in the transitional year must mirror the allocations in the final year of the current regulatory control period.
- Subclause 11.56.3(h)(1) suggests the classification of a distribution service in the subsequent control period must be the same as in the transitional year.

In practical terms it makes sense for as few changes as possible be made in the transitional year. This is because there will be limited or no opportunity to consult with the stakeholders on any potential changes. As it is possible that some changes to ACS services may have significant implications for consumers, it makes sense to minimise these changes in the transitional year.

Based on our assessment of the transitional rules, the pricing of ACS services in the transitional year appears to fall into four main groups:

1. ACS that were ACS in the current period (e.g. public lighting)
2. ACS that were standard control services (SCS) in the current period and for which there were no approved prices in the current period (e.g. types 5 and 6 metering services)
3. ACS that were SCS in the current period and for which there were approved prices in the current period (the so called 'monopoly and miscellaneous services')
4. ACS that will be entirely new in the transitional year and for which there is no current cost allocations approach that could be retained (for example, perhaps NECF related services).

Prices for services in group 1 should be indexed by CPI in the transitional year, consistent with subclause 11.56.3(j). Further, we think it may not be necessary to true up these prices in the subsequent regulatory period. However, the AER is open to suggestions from the DNSPs on how a true up arrangement might work for services in this group. The true up arrangements, if any, will be clarified in the AER's determination on the transitional regulatory proposal.

For group 2, we consider the new prices for these services should not be applied in the transitional year. This is because the costs of providing these services are already captured in the standard control building blocks through the application of subclause 11.56.3(i), which requires cost allocations in the transitional year to mirror those in the final year of the current regulatory control period. While these services will be reclassified as ACS in the transitional year (through the operation of subclause 11.56.3(h)(1)), there would be no effective change to the regulatory treatment of these services in the transitional year if no prices are set. Furthermore, as these services have not been charged for previously, we consider consultation with consumers and other stakeholders is important before a new charging regime is introduced. A reconciliation of the costs of these services will be required to the extent that the standard control building blocks require an adjustment as part of the AER's final distribution determination for the subsequent regulatory control period. Consequently, any reconciliation would only relate to standard control building block costs of group 2 services.

Group 3 services encompass services previously referred to as monopoly and miscellaneous services. Under our preferred approach, prices for these services should be indexed by CPI (through the operation of subclause 11.56.3(j)). The costs should be included in the standard control building blocks, which is consistent with the approach in the current regulatory period (and required by subclause 11.56.3(i)). Revenues raised from prices paid for these services would need to be deducted from the revenue requirement in the transitional year to avoid over-recovery. With respect to a reconciliation of revenues, the approach would be the same as group 2. That is, prices paid by customers would not be revisited. However, costs associated with these services that are included in the building blocks may be revisited in the AER's final determination (as per group 2).

The final group of ACS relates to new services. Being new, prices for these services should be based on cost reflective charges in the transitional year. Unless, that is, there is an existing cost allocation approach for this type of service that would be captured under subclause 11.56.3(i). It is difficult for us to be definitive about this group of ACS services without more information. It is anticipated that no reconciliation would be required for this group of services.

As noted earlier, I emphasise that these views have not been endorsed by the AER. In addition, when the distributors submit their transitional regulatory proposals, we intend to publish these documents and seek comments from stakeholders. The transitional determination approved by the AER in April

2014 will take account of the views expressed in submissions, including any comments on the approach to ACS pricing in the transitional year.

If there are any aspects of this approach you consider should be reconsidered, please let me know. You can contact me on 02 6243 1240 or Moston Neck on 07 3835 4669.

Yours sincerely

for Warwick Anderson
General Manager
Network Regulation