Final framework and approach paper

Application of schemes

Energex and Ergon Energy 2010–15

November 2008

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Shortened forms

AER	Australian Energy Regulator
capex	capital expenditure
DNSP	distribution network service provider
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
EBSS	efficiency benefit sharing scheme
EDSD	Electricity Distribution and Service Delivery review
EIC	electricity industry code (Queensland)
FRC	full retail competition
GSL	guaranteed service levels
kV	kilovolt (one thousand volts)
MAIFI	momentary average interruption frequency index
MED	major event day
MSS	minimum service standards
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
opex	operating expenditure
QCA	Queensland Competition Authority
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
VCR	value of customer reliability

1 Introduction

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services in the National Electricity Market (NEM). The AER's functions and powers are set out in the National Electricity Law (NEL) and the National Electricity Rules (NER).

Chapter 6 of the NER sets out the AER's responsibilities in relation to the economic regulation of Distribution Network Service Providers (DNSP). There are two Queensland DNSPs subject to economic regulation under chapter 6 of the NER:

- Energex—whose network covers mainly urban areas in South East Queensland
- Ergon Energy (Ergon)—whose network covers regional areas throughout Queensland.

Queensland distribution networks are currently subject to economic regulation by the Queensland jurisdictional regulator, the Queensland Competition Authority (QCA). The QCA released a distribution determination in April 2005 for the current regulatory period—1 July 2005 to 30 June 2010. The QCA is responsible for administering its 2005 distribution determination.

The AER will assume responsibility for the economic regulation of Energex and Ergon on 1 July 2010, with the commencement of the first distribution determinations for those businesses. The next regulatory control period for the Queensland DNSPs is from 1 July 2010 to 30 June 2015. The AER commenced the process of making those distribution determinations on 1 April 2008.

1.1 Nature of framework and approach paper

The AER must prepare and publish a framework and approach paper in anticipation of every distribution determination. The AER must commence preparation of and consultation on its framework and approach at least two years prior to the end of the current regulatory control period and complete its framework and approach paper 19 months prior to the end of that regulatory control period.

The aim of the framework and approach paper is to assist a DNSP prepare its regulatory proposal by:

- stating the form (or forms) of control to be applied by the distribution determination and the AER's reasons for deciding on control mechanisms of the relevant form or forms
- setting out the AER's likely approach (and its reasons for that approach) in the distribution determination to:
  - the classification of distribution services
  - the application to the DNSP of a service target performance incentive scheme or schemes

- the application to the DNSP of an efficiency benefit sharing scheme or schemes
- the application to the DNSP of a demand management incentive scheme or schemes
- any other matters on which the AER thinks fit to give an indication of its likely approach.[1]

The classification of services in the distribution determination must be as set out in the framework and approach paper, clause 6.12.3(b), unless the AER considers that there are good reasons for departing from the classification of services set out in the framework and approach paper. The control mechanisms set out in the distribution determination must be as set out in the framework and approach paper under clause 6.12.3(c). Clause 6.8.1(h) states that the framework and approach paper is not otherwise binding on the AER or a DNSP.

The framework and approach paper must also include the AER's determination as to whether or not Part J of chapter 6A of the NER is to be applied to determine the pricing of transmission standard control services provided by any dual function assets owned, controlled or operated by the DNSP.[2, 3] If a DNSP owns, controls or operates dual function assets, it must advise the AER of the value of those assets 24 months prior to the end of the current regulatory control period to enable such a determination.[4]

Clause 6.8.1(ca) took affect on 1 July 2008, after the AER published its preliminary positions framework and approach paper—application of schemes. Energex and Ergon have informed the AER that they do not control, own or operate any dual function assets, as provided by the Jurisdictional Derogations for Queensland in Chapter 9 of the NER.[5] Therefore, this final framework and approach paper does not include a determination on dual function assets made under clause 6.25(b).

1.2 Transitional arrangements

Chapter 6 of the NER sets out the arrangements for the economic regulation of distribution services, while chapter 11 sets out transitional arrangements specific to different NEM jurisdictions. Clause 11.16 sets out transitional arrangements that are

1 NER, clause 6.8.1.

2 NER, clause 6.8.1(ca).

3 A dual function asset is any part of a network owned, operated or controlled by a DNSP which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network which is deemed by clause 6.242(a) to be a dual function asset. For the avoidance of doubt:

(a) a dual function asset can only be an asset which forms part of a network that is predominantly a distribution network; and

(b) an asset which forms part of a network which is predominantly a transmission network cannot be characterised as a dual function asset,

through the operation of clause 6.24(a).

4 NER, clause 6.25.

5 Clause 9.32.1(b) of the Jurisdictional Derogations for Queensland states that the transmission network assets in Queensland are only those that are owned by PowerLink or any other transmission network service provider.

to apply to Energex and Ergon for the distribution determinations that cover the 1 July 2010 to 30 June 2015 regulatory control period.

Due to the transitional arrangements, the framework and approach paper for Energex and Ergon has been undertaken in two stages:[6]

1. Framework and approach—classification of services and control mechanisms

2. Framework and approach—application of schemes.

This framework and approach paper sets out the AER's likely approach to Energex and Ergon in the 2010–15 regulatory control period in relation to:

- the application of a service target performance incentive scheme (STPIS)
- the application of an efficiency benefit sharing scheme (EBSS)
- the application of a demand management incentive scheme (DMIS)
- other matters the AER thinks fit to give an indication of its likely approach.

On 27 August 2008, the AER published a separate framework and approach paper setting out its likely approach to the classification of Energex's and Ergon's distribution services and the control mechanisms to apply to standard control services and alternative control services in the 2010–15 regulatory control period. This paper and associated documentation is available on the AER's website.[7]

1.3 Consultation on framework and approach paper

In order to consider common issues and for administrative simplicity the framework and approach papers for Energex and Ergon are being considered through a joint process. Where necessary, the AER has considered issues separately. The consultation process was streamlined to allow for interested parties to respond to both or either proposal as necessary.

Under clause 6.8.1(f) the AER must complete and publish its framework and approach paper—application of schemes no later than 30 November 2008.

1.4 Structure of framework and approach paper

This paper sets out the AER's consideration of substantive issues raised in submissions on its preliminary positions paper. Except where specified, the AER will adopt the preliminary positions set out in its June 2008 positions paper.

The structure of this framework and approach paper is set out as follows:

- Chapter 2 sets out the AER's likely approach to the application of a STPIS to Energex and Ergon

[6] Both Energex and Ergon submitted classification of services and control mechanism proposals to the AER on 31 March 2008 in accordance with clause 11.16.6 of the NER.

[7] www.aer.gov.au.

- Chapter 3 sets out the AER’s likely approach to the application of an EBSS to Energex and Ergon
- Chapter 4 sets out the AER’s likely approach to the application of a DMIS to Energex and Ergon
- Chapter 5 sets out the AER’s likely approach to ‘other matters’.

2 Application of a service target performance incentive scheme

2.1 Introduction

This chapter sets out the AER's likely approach, and the reasons for that approach, to the application of a service target performance incentive scheme (STPIS) to be applied to Energex and Ergon in the 2010–15 regulatory control period. However, the actual application of the scheme to the DNSPs will be set out in the AER's distribution determinations for the 2010–15 regulatory control period.

2.2 Requirements of the National Electricity Rules

The NER requires the AER to include in its distribution determination a decision on how the STPIS will apply to the DNSP for the relevant regulatory control period.[8] The framework and approach paper must set out the AER's likely approach to the application of a STPIS in its forthcoming distribution determination.[9]

AER's distribution STPIS

The AER published the national distribution STPIS on 26 June 2008. The scheme and associated decision documents are available on the AER's website.

Structure of the STPIS

The STPIS consists of four components:

1.	Reliability of supply	S-factor
2.	Quality of supply	S-factor
3.	Customer service	S-factor
4.	Guaranteed service levels	

These components can apply in isolation or in combination within a distribution determination.

S-factor

The first three components of the scheme are collectively known as the s-factor. Application of one or more of these three components takes the form of a financial reward or penalty (in the form of a revenue increment or decrement) commensurate with service performance that is better than or below predetermined targets. The maximum revenue at risk under the s-factor is ± 3 per cent of a DNSP's revenue for each year of the regulatory control period.[10]

8 NER, clause 6.3.2 (a)(3).
9 NER, clause 6.8.1 (b)(2).
10 The AER retains discretion under the STPIS to alter this figure where doing so would achieve the objectives set out in clause 6.6.2 of the NER.

Reliability of supply component

Three parameters are available under the reliability of supply component of the STPIS:

- Unplanned system average interruption duration index (SAIDI)
- Unplanned system average interruption frequency index (SAIFI)
- Momentary average interruption frequency index (MAIFI).[11]

The performance target for each of these parameters is based on a DNSP's average historical performance over the last five years.[12] Targets for each parameter are set for segments of the distribution network identified, for example, by feeder type. This allows the STPIS to recognise variations in performance across the DNSP's network.

The incentive rates for this component, which determine the amount of any reward or penalty, are based on the value that customers place on reliability of supply.

Quality of supply component

There is no quality of supply component included in the scheme at this time.

Customer service component

There are four available parameters in the customer service component of the STPIS:

- telephone answering
- streetlight repair
- new connections
- response to written enquiries.

Of these, the STPIS assumes that telephone answering will be included as a parameter for each DNSP to which the customer service component applies. One or more of the remaining parameters may apply under the customer service component where application of that parameter is justified under the NER.

As with reliability of supply, customer service performance targets are based on average performance over the previous five years.[13] Unlike targets for the reliability

[11] SAIDI refers to the sum of the duration of each sustained customer interruption (in minutes) divided by the total number of distribution customers. SAIFI refers to the total number of sustained customer interruptions divided by the total number of distribution customers. MAIFI refers to the total number of customer interruptions of one minute or less, divided by the total number of distribution customers.

[12] This data is adjusted to account for improvements in reliability which have been included in the DNSP's planned or completed expenditure programs, and adjusted for any other material factors expected to affect network reliability performance: targets will not necessarily be equal to average performance over the previous five years.

[13] This data is adjusted to account for improvements in reliability which have been included in the DNSP's planned or completed expenditure program, and adjusted for any other material factors expected to affect network reliability performance. This means that targets will not necessarily be equal to average performance over the last five years.

of supply component of the STPIS, targets for this component apply to the distribution network as a whole, and different targets are not set for different segments of the network.

The incentive rate for the telephone answering parameter is set at minus 0.040, or a value determined from an applicable assessment of the value that customers attribute to the level of service proposed.[14]

Reporting requirements

The STPIS requires the DNSP to report its performance annually against all applicable parameters.[15]

Guaranteed service levels

The purpose of a guaranteed service levels (GSL) scheme is to provide payments to individual customers if the level of service they experience falls below a predetermined level. The GSL scheme can operate independently of the s-factor scheme. The AER will not apply the GSL component of its STPIS to DNSPs while they remain subject to a jurisdictional GSL scheme.

Implementing the STPIS

In implementing the STPIS, the AER must:

- 6.6.2(b)(1)—consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation
- 6.6.2(b)(2)—ensure that service standards and service targets (including GSL) set by the scheme do not put at risk the DNSP's ability to comply with relevant service standards and service targets (including GSL) as specified in jurisdictional electricity legislation.[16]

The AER must also take into account:

- 6.6.2(b)(3)(i)—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
- 6.6.2(b)(3)(ii)—any regulatory obligation or requirement to which the DNSP is subject
- 6.6.2(b)(3)(iii)—the past performance of the distribution network
- 6.6.2(b)(3)(iv)—any other incentives available to the DNSP under the NER or a relevant distribution determination

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14 AER, *Electricity distribution network service providers Service target performance incentive scheme*, June 2008, clause 5.3.2(a), p. 15.

15 These reporting requirements relate to the application and operation of the STPIS under the distribution determination by which it is applied. Additional annual reporting requirements may apply to a DNSP via any applicable regulatory information order.

16 The STPIS operates concurrently with any average or minimum service standards and GSL schemes that apply to the DNSP under jurisdictional electricity legislation.

- 6.6.2(b)(3)(v)—the need to ensure that the incentives are sufficient to offset any financial incentives the DNSP may have to reduce costs at the expense of service levels
- 6.6.2(b)(3)(vi)—the willingness of the customer or end user to pay for improved performance in the delivery of services
- 6.6.2(b)(3)(vii)—the possible effects of the scheme on incentives for the implementation of non-network alternatives.

Clause 11.16 of the NER sets out transitional arrangements for Energex's and Ergon's 2010–15 distribution determinations. In formulating the STPIS to apply to Energex and Ergon, in addition to the requirements in clause 6.6.2(b), the AER must also:

- 11.16.5(1)—take into account the continuing obligations on Energex and Ergon throughout the regulatory control period to implement the recommendations from the Electricity Distribution and Service Delivery (EDSD) review adopted by the Queensland Government
- 11.16.5(2)—take into account the impact of severe weather events on service performance
- 11.16.5(3)—consider whether the scheme should be applied by way of a paper trial or whether a lower powered incentive is appropriate.

2.3 AER preliminary positions

The preliminary position was that the reliability of supply and customer service components of the STPIS will apply to Energex and Ergon in the 2010–15 regulatory control period.[17]

Under the reliability of supply component, the preliminary position was that the unplanned SAIFI and unplanned SAIDI parameters would apply to Energex and Ergon. STPIS performance targets would be established at or above the current minimum service standards (MSS) levels established by the Queensland Competition Authority (QCA). The MAIFI parameter would not be applied to the DNSPs as they do not have the data gathering capacity to measure momentary interruptions.

Within the customer service component, the preliminary position was to apply the telephone answering parameter in the next regulatory control period to Energex and Ergon.

The STPIS does not include any quality of supply parameters. The AER stated that the DNSPs will be required to measure and report quality of supply data in the next regulatory control period.

Consistent with its STPIS, the preliminary position was that the GSL component of the scheme would not apply to Energex and Ergon in the next regulatory control period as the DNSPs are subject to a jurisdictional GSL scheme.

[17] AER, *Framework and approach paper—Application of schemes Energex and Ergon Energy 2010–15*, Preliminary positions, June 2008.

2.4 Submissions

Energex and Ergon provided submissions commenting on the positions paper. No other submissions were received. The main issues raised in submissions were in relation to:

- the interaction of the STPIS with the MSS
- components and parameters
- performance targets
- the amount of revenue at risk
- exclusions.

The DNSPs also sought a number of clarifications concerning the practical operation of the STPIS.

2.5 Issues and considerations

The preliminary position on the application of the STPIS to Energex and Ergon had regard to the factors outlined in clause 6.6.2 of the NER. This section sets out the AER's consideration of issues raised in submissions on its preliminary positions paper. The AER's consideration of the factors in clause 6.6.2 is discussed in section 2.5.7 of this paper.

2.5.1 Interaction of the STPIS with the MSS and GSL obligations

AER preliminary position

The preliminary position was to apply the national distribution STPIS to Energex and Ergon in the 2010–15 regulatory control period. It was noted that the STPIS would be implemented concurrently with the MSS and GSL contained in the electricity industry code (EIC) and that performance targets would be established at or above the current minimum service levels.

Submissions

Energex stated that the key objectives of a STPIS are currently addressed in Queensland through the MSS and GSL obligations set out in the EIC. It stated that both the MSS and the STPIS aim to ensure that distributors maintain and improve service performance.[18]

Energex stated that it is largely unclear how the STPIS will interact with the MSS and submitted that a paper trial, in conjunction with the MSS and GSL would satisfy the objective of the STPIS.[19]

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18 Energex, *Response to the AER's Preliminary Positions, Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15,* August 2008, p. 7.

19 Energex, op cit., pp. 5–7.

AER consideration

The regulatory framework under the NER provides an incentive for DNSPs to become more cost efficient. A DNSP may seek to reduce its costs in two ways:

- realising productive efficiencies
- deferring expenditure on forecast programs leading to a reduction in service performance.

One objective of the STPIS is to balance a DNSP's incentive to reduce expenditure with the need to maintain and improve its service performance.

In implementing the scheme the AER is required to take account of any regulatory obligations or requirements to which a DNSP is subject.[20] Clauses 2.4 and 2.5 of the EIC outline the MSS and GSL respectively.[21] Schedule 1 of the EIC sets out the performance targets for unplanned SAIDI and SAIFI and requires that each DNSP use its 'best endeavours' to ensure that service performance is better than these targets.[22]

In applying the STPIS to Energex and Ergon, the AER must ensure that service standards and service targets (including GSL) set by the scheme do not put at risk their ability to comply with relevant service standards and service targets (including GSL) as specified in jurisdictional electricity legislation.[23]

Energex stated that it is largely unclear how the scheme will interact with the MSS. It noted that it was possible that a STPIS bonus could be paid to a DNSP at the same time as its performance was not meeting the mandated MSS.[24] Energex also noted concern with the level of uncertainty with operation of the scheme with the uncertainty surrounding potential changes to its MSS and GSL obligations.[25]

The NER envisages the STPIS to operate concurrently with any MSS and GSL schemes that apply to a DNSP under jurisdictional electricity legislation.[26] In other words the scheme can operate while a DNSP is also subject to any jurisdictional based average or minimum service standards and GSL schemes.

The above scenario submitted by Energex could occur. A specific set of principles designed to avoid such a scenario when establishing performance targets for Energex's and Ergon's reliability of supply parameters will be implemented. These principles can also incorporate any changes to the MSS targets. The principles for establishing performance targets are set out in section 2.5.3.

Using these principles to establish performance targets addresses the major concerns raised by Energex with respect to the interaction of the STPIS with the MSS. Therefore, the AER considers the application of the scheme will not put at risk Energex's or Ergon's ability to comply with their respective MSS obligations.

20 NER, clause 6.6.2(b)(3)(ii).
21 Electricity Industry Code (Queensland), fourth edition, pp. 16–25 and 125.
22 ibid.
23 NER, clause 6.6.2(b)(2).
24 Energex op. cit., p. 7.
25 ibid., p. 8.
26 NER, note to clause 6.6.2(b)(2).

The application of the STPIS will not affect Energex's or Ergon's regulatory obligations to comply with the GSL scheme set out in the EIC. Clause 6.1(a) of the STPIS provides that where jurisdictional electricity legislation imposes an obligation on a DNSP to operate a GSL scheme, the GSL component of the STPIS will not apply to that DNSP. Consistent with clause 6.1(a), the preliminary position was not to apply the GSL component of the scheme to the DNSPs. Energex and Ergon supported this position. The AER considers it appropriate to adopt its preliminary position.

The AER assessment of clause 6.6.2(b)(2) indicates that applying the STPIS does not put at risk Energex's or Ergon's ability to comply with their MSS and GSL obligations.

2.5.2 Components and parameters

AER preliminary position

The preliminary position was to apply its national distribution STPIS to Energex and Ergon in the 2010–15 regulatory control period. In applying the scheme to the DNSPs the AER decided:

- to apply the unplanned SAIDI and unplanned SAIFI parameters of the reliability of supply component of the scheme but not to apply the MAIFI parameter
- to apply the telephone answering parameter of the customer service component of the STPIS but not to apply the streetlight repair, new connections and response to written enquires parameters
- not to apply the quality of supply component of the scheme
- not to apply the GSL component of the scheme.

Submissions

Energex supported the inclusion of the unplanned SAIDI and unplanned SAIFI parameters and the exclusion of the MAIFI reliability of supply parameter. It also supported the exclusion of the quality of supply and GSL components of the STPIS.[27]

Energex however proposed that its CBD network segment of the unplanned SAIDI and unplanned SAIFI parameters and the telephone answering customer service parameter be excluded from the scheme.[28]

AER consideration

This section sets out the AER's consideration of the STPIS components and parameters to apply to Energex and Ergon in the next regulatory control period.

Energex's CBD network segment

Energex stated that its CBD SAIDI and SAIFI feeder performance is very good in absolute and relative terms and is already significantly better than the existing MSS and that there is limited opportunity for further improvement.[29] It submitted that

[27] Energex op. cit., p. 11.
[28] ibid.

penalties for small declines in performance represent a higher risk than the opportunity for improvement and on that basis the CBD network segment should be excluded from the scheme.[30]

The STPIS aims to provide incentives for DNSPs to maintain and improve service performance. Energex was provided with an allowance to provide a level of service that over time has exceeded the MSS. Excluding this feeder type from the scheme based on Energex's concern that its performance might decline is not consistent with the aims of the STPIS. Therefore, Energex's CBD feeder type will not be excluded from the scheme.

Energex's telephone answering parameter

Energex stated that due to the introduction of full retail competition (FRC) its call centre data, and telephone answering historical data is not reflective of its current operations and proposed that this parameter be excluded from the scheme.[31]

Performance targets for the customer service parameters must be established according to clause 5.3.1 of the STPIS in the distribution determination for Energex. The scheme provides flexibility in establishing performance targets for the customer service parameters, specifically:

- clause 5.3.1(b)(2) requires performance targets to be modified to account for other factors that are expected to materially affect the service being measured by the parameter, such as the introduction of FRC

- clause 5.3.1(d) provides that where five years data is not available the AER may approve performance targets based on an alternative methodology or benchmark.[32]

FRC came into operation in July 2007. By the time Energex's regulatory proposal is assessed two year's data will be available. This data and the pre FRC data will be evaluated as part if the assessment of the regulatory proposal.

The AER considers that the introduction of FRC is not a sufficient reason to exclude this parameter given that the STPIS provides flexibility to take account of the changed circumstances of Energex's telephone answering service.

Applicable STPIS components and parameters to Energex and Ergon

The AER will adopt its preliminary positions in that it will not apply the MAIFI reliability of supply, the streetlight repair, new connections and response to written enquires customer service parameters. The quality of supply component and the GSL component of the STPIS will not apply to Energex and Ergon in the next regulatory control period.

Consistent with its preliminary positions, the AER will apply its national distribution STPIS to Energex and Ergon in the next regulatory control period incorporating:

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[29] Energex op. cit., p. 7.
[30] ibid.
[31] ibid., pp. 9–11.
[32] AER, *Electricity distribution network service providers Service target performance incentive scheme*, June 2008, clause 5.3.1, p. 15.

- The unplanned SAIDI and unplanned SAIFI parameters of the reliability of supply component of the scheme.

- The telephone answering parameter of the customer service component of the scheme.

2.5.3 Performance targets

This section sets out the principles the AER will use to establish performance targets for those parameters.

AER preliminary position

The AER indicated that STPIS performance targets would be established at or above the current MSS levels.[33]

Submissions

Energex and Ergon sought confirmation that performance targets established under the STPIS would be constant throughout the regulatory control period.[34, 35]

Energex expressed concern with how performance targets would be established with reference to historical data and the MSS.[36] Ergon sought clarification on how the AER intends to take account of both the MSS and its historical performance in setting STPIS performance targets.[37]

Ergon sought clarification on how performance targets will be modified for reliability improvements.[38]

AER consideration

Reliability of supply component

The operation of the national distribution STPIS can accommodate constant or variable targets.

The MSS targets require an improved level of service over the next regulatory control period.[39]

Both DNSPs have indicated that they intend to propose capital expenditure (capex) and operating expenditure (opex) in the next regulatory control period to achieve the MSS targets.[40, 41] Thus it is appropriate for these performance targets to underpin the

33 AER op. cit., p. 18.
34 ibid., p. 9.
35 Ergon, *Submission to the AER in response to "Preliminary positions – Framework and approach paper – Application of Schemes – Energex and Ergon Energy 2010–15"*, August 2008, p. 10.
36 Energex op. cit., p. 8.
37 Ergon op. cit., p. 10.
38 ibid.
39 Clause 2.4.4 of the EIC requires the QCA to review the MSS to apply at the beginning of each regulatory control period. The MSS targets for 2010–11 to 2014–15 set out in the fourth edition of the EIC are indicative as the QCA has not completed its review. The QCA expects to complete its review in February 2009.
40 Energex, response to information request, submitted 20 October 2008.
41 Ergon, response to information request, submitted 20 October 2008.

STPIS.[42] If performance targets are set on the basis of average historical data it would be possible for the DNSP's to be rewarded for achieving higher performance standards even though capex and opex allowances have been provided to fund this level of service.

On that basis, the AER does not consider that performance targets established under the STPIS should be set at levels below the MSS.[43] SAIDI and SAIFI performance targets established under the scheme should be determined according to the following principles:

- Each DNSP's average historical performance should be modified to reflect the exclusions and definitions contained in the AER's STPIS. This modification allows for performance targets to be established on a consistent basis with how the DNSPs performance will be measured and reported during the regulatory control period.

- The DNSP's average historical performance should be modified according to clause 3.2.1(a) of the scheme to account for completed or planned reliability improvements and any other factor expected to materially affect network reliability performance.

- For network segments where the DNSP's modified average historical performance is below the MSS performance targets for that regulatory year, the performance target for that parameter will be set equal to the MSS target for that regulatory year. This provides the incentive for Energex and Ergon to improve service performance to the MSS level they are funded to provide.

- For network segments where the DNSP's modified average historical performance is better than the MSS performance target for that regulatory year, the performance target for that regulatory year will be set equal to the average historic performance. This provides the incentive for Energex and Ergon to maintain their average historical service performance.

These principles provide each DNSP the incentive to maintain and improve service performance consistent with the objective of the STPIS. These principles will be applied in the distribution determinations for Energex and Ergon.

The QCA is expected to complete its review of the MSS and GSL to apply in the 2010–15 regulatory control period in February 2009.[44] The AER will take account of the MSS established by this review and 2008–09 service performance data when it establishes performance targets using the above mentioned principles as part of its distribution determination.[45]

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[42] There may be methodological differences between the measurement of service performance under the STPIS and the MSS.

[43] That is, the STPIS targets should not be set at a level which provides the DNSP with a less onerous target than the MSS.

[44] QCA, *Review of Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to Apply in Queensland from 1 July 2010,* Discussion Paper, July 2008, p. 4.

[45] The MSS does not differentiate between planned and unplanned interruptions whereas the STPIS only measures unplanned interruptions.

Customer service component

Energex stated that following the introduction of FRC its call centre data and telephone answering historical data is not reflective of its current operations and proposed that this parameter be excluded from the scheme.[46] As noted above, the AER has decided that it will not exclude Energex's telephone answering customer service parameter from the STPIS as the scheme provides flexibility to take account of Energex's changed circumstances. Energex's telephone answering performance targets will be based on an evaluation of post FRC and pre FRC historical data in accordance with clause 5.3.1(b)(2) and 5.3.1(d) of the STPIS.

Ergon indicated that its current performance did not deviate from historical performance due to the introduction of FRC.[47] Therefore, Ergon's telephone answering performance targets will be based on the average of its historical performance modified in accordance with clause 5.3.1(b) of the scheme. In establishing performance targets for Ergon's telephone answering parameter 2008–09 performance data will be included.

Modification for reliability improvements

Clause 3.2.1(a) and 5.3.1(b) of the STPIS states that performance targets for the reliability of supply and customer service parameters must be established with reference to average historical performance modified to account for completed or planned reliability improvements and any other factor expected to materially affect network reliability performance.

The AER does not have a preferred method for how this modification should be undertaken. However, such a modification must take account of expenditure programs completed in the regulatory period or planned to be undertaken in the next regulatory control period and the benefits these programs are expected to deliver to the DNSP's network. Any proposed modification will need to be supported by statistical analysis.

Energex noted that targets based on historical performance would not reflect usual weather patterns.[48] Clause 11.16.5(2) requires the AER to consider the impact of severe weather on service performance. To this end, the AER considers that Energex can propose performance targets modified to account for usual weather conditions. Any proposed performance targets and modifications will be considered in making the distribution determination.

In summary, the AER will apply the above principles in its distribution determinations for Energex and Ergon incorporating any revised MSS targets and 2008–09 service performance data to establish performance targets to apply in the next regulatory control period.

[46] ibid., pp. 9–11.
[47] Ergon, response to information request, submitted 20 October 2008.
[48] Energex op. cit., p. 8.

2.5.4 Revenue at risk

AER preliminary position

The preliminary position was to apply its national distribution STPIS to Energex and Ergon in a form as close as possible to the national scheme that is with ± 3 per cent of revenue at risk.

Submissions

Energex stated that the AER's preliminary position to apply its STPIS with ± 3 per cent of revenue at risk did not give adequate consideration to the transitional arrangements in clause 11.16.5 of the NER. It stated that the scheme should be applied as a paper trial for the next regulatory period.[49]

Ergon stated that it has never operated under any form of STPIS and noted the AER's decision to apply a paper trial to the ACT and NSW DNSPs. It submitted that the AER must have regard to the transitional arrangements, which allows for the scheme to be applied through a lower powered scheme or paper trial for the 2010–15 regulatory control period.[50]

AER consideration

The AER must consider the factors in clause 6.6.2(b) of the NER when implementing a STPIS. In addition, clause 11.16.5(3) of the transitional arrangements requires the AER to consider whether the scheme should be applied by way of a paper trial or whether a lower powered incentive is appropriate.

Implementing the STPIS by way of a paper trial means that while relevant data is collected and ensuing rewards and penalties are calculated no revenue is placed at risk. That is, the scheme would not apply a financial incentive.

Clause 6.6.2(b)(3)(v) requires the AER to take account of the need to ensure that the incentives under the STPIS are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels. The AER considers that applying the STPIS without a financial incentive may not offset any financial incentive Energex and Ergon have to reduce costs at the expense of service levels. To ensure the effective operation of the STPIS the AER considers it important that a financial incentive be applied during the next regulatory control period.

Energex and Ergon both stated that they have no experience operating under a STPIS style scheme and are unfamiliar with its operation.[51, 52] The AER recognises that the STPIS is a different type of scheme for Energex and Ergon to operate under. However, both DNSPs have been measuring and reporting SAIDI, SAIFI and telephone answering performance since 2002–03.[53] As discussed in section 2.5.2, the scheme to apply to Energex and Ergon will only apply to these parameters. On that

49 Energex op. cit., pp. 5–7.
50 Ergon op. cit., p. 6.
51 Energex op. cit., p. 6.
52 Ergon op. cit., pp. 5–6.
53 QCA, *Electricity Distribution Businesses' Financial and Service Quality Performance 2002–03*, March 2004.

basis, the AER does not consider the DNSPs lack of experience in operating under a STPIS to be a sufficient reason for the STPIS to be applied by way of a paper trial.

Ergon also noted that the AER elected to apply its STPIS by way of a paper trial to the ACT and NSW DNSPs in the 2009–14 regulatory control period.[54]

The AER notes that clause 6.2.2(k) of the transitional chapter 6 rules of the NER provided that a STPIS applying to ActewAGL must not, without its agreement, confer financial rewards or penalties for the 2009–14 regulatory control period. ActewAGL did not support the application of a scheme with revenue at risk, and as a result a paper trial has only been applied.[55]

In implementing a STPIS to the NSW DNSPs the AER decided that it should not apply a scheme with revenue at risk primarily due to concerns with data availability and accuracy, and the implications for design of an appropriate scheme with financial impact in the limited time available.[56] The issues that prevented a STPIS with a financial incentive being applied to the NSW DNSPs do not exist in Queensland, given that:

- Both Energex and Ergon have sufficient historical data suitable for calculating performance targets. The DNSPs have reported SAIDI, SAIFI and telephone answering performance since 2002–03.[57] The feeder definitions in the EIC are consistent with appendix A of the STPIS.

- In terms of the design of the scheme, the national distribution STPIS was developed in accordance with clause 6.6.2(b) and 11.16.3 of the NER and the distribution consultation procedures. The development of the STPIS took into account submissions from both Energex and Ergon. The scheme was finalised on 26 June 2008 well before the DNSPs next regulatory control period giving them sufficient time to prepare and gain experience with its operation.

The AER acknowledges Energex’s and Ergon’s limited experience and reservations about operating under a new style of scheme. The AER also notes that neither DNSP has ever operated under a scheme that places a portion of their revenue at risk. The DNSPs inexperience in implementing a scheme that places revenue at risk is not by itself a sufficient reason to apply the STPIS by way of a paper trial. However, the AER is also required by clause 11.16.5(3) of the transitional arrangements to consider whether applying the scheme by way of a lower powered incentive is appropriate.

As the DNSPs have not previously operated under a scheme that places a portion of revenue at risk and the transitional arrangements require consideration of a lower powered incentive, the AER considers it reasonable in this instance to apply the STPIS to Energex and Ergon by way of a lower powered incentive.

[54] Ergon op. cit., p. 6.

[55] ActewAGL, *ActewAGL response to AER Preliminary Positions Paper*, January 2008, p. 11.

[56] AER, *Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, February 2008, p. 15.

[57] QCA, *Electricity Distribution Businesses’ Financial and Service Quality Performance 2002–03*, March 2004.

The AER notes that jurisdictional regulators that have introduced new service standards schemes have initially placed between 1 and 2 per cent of revenue at risk.[58] In considering transitional clause 11.16.5(3), the AER has been mindful of the initial financial incentive imposed in other jurisdictions and considers it reasonable to apply its STPIS to Energex and Ergon with ± 2 per cent of revenue at risk.

In summary, the AER does not consider it appropriate to apply its STPIS to Energex and Ergon in the next regulatory control period by way of a paper trial. However, consistent with the scheme and clause 11.16.3(c) the AER will apply the STPIS the DNSPs with a lower powered incentive of ± 2 per cent of revenue at risk.

2.5.5 Exclusions under the STPIS

AER preliminary position

The preliminary position was to apply its national distribution STPIS to Energex and Ergon in the 2010–15 regulatory control period. The AER considered it appropriate to apply the scheme to the DNSPs in a form as close as possible to the national scheme.

Submissions

Ergon noted that there are differences between the exclusions events listed in the STPIS and the MSS in the EIC.[59] Energex and Ergon requested the AER include the following EIC exclusions in the STPIS:[60, 61]

- interruptions caused by a customer's electrical installation or failure of that installation
- a direction by police officer or another authorised person exercising powers in relation to public safety.

Energex stated that it was also concerned about the cost and potential confusion to the public in reporting two sets of performance data.[62]

Ergon also sought clarification that the major event day (MED) boundary would be calculated annually to ensure consistency with the EIC.[63]

AER consideration

In developing its national distribution STPIS, the AER decided not to include these two exclusion events in the scheme, specifically it stated that:[64]

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58 ESCOSA, *2005 – 2010 Electricity Distribution Price Determination Part A – Statement of Reasons*, April 2005, p. 48.
OTTER, *Investigation of prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Price*, September 2003, p. 119.
Office of the Regulator-General, Victoria, *Electricity Distribution Price Determination 2001–2005 Volume 1 Statement of Purpose and Reasons*, September 2000. (The amount of revenue at risk was uncapped and to date the greatest change in annual revenue has been 2.6 per cent).

59 Ergon op. cit., pp. 6–7.

60 Energex op. cit., p. 8.

61 Ergon op. cit., pp. 6–7.

62 Energex op. cit., p. 8.

63 Ergon op. cit., p. 10.

> Exclusions at the direction of police and other authorised emergency personnel have not been specifically included in the final STPIS. The AER considers that such events do not occur often and will generally have a minor impact on performance, which will in any case be reflected in the historical data used to set targets under the reliability parameters in the STPIS. The AER notes that where such directions are associated with a major event (for example, a major storm or bushfire) the event would generally be captured by the 2.5 beta method exclusion criteria.
>
> Exclusions due to a customer's electrical installation have also not been specifically included in the final STPIS on the basis that it is often difficult to determine whether a customer's installation has caused a service interruption or whether the interruption is due to a distribution network protection system not responding appropriately to a customer fault. Also, outages due to a customer's electrical installation are unlikely to be material to the performance measured under the reliability parameters in the STPIS.

The NER envisages the STPIS to operate concurrently with any average or minimum service standard and GSL schemes that applies to a DNSP under jurisdictional electricity legislation.[65]

The STPIS was not designed to replace any average or minimum service standards and GSL schemes applicable to a DNSP under jurisdictional electricity legislation but rather to operate concurrently with jurisdictional schemes. As such, it is not necessary for the exclusions contained in clauses 3.3 and 5.4 of the scheme to mirror or align with existing jurisdictional average or minimum service standard and GSL schemes.

The STPIS was designed to be applied on a nationally consistent basis. The AER considers it important to maintain consistency in the exclusions that will apply to all DNSPs in order to reduce compliance and administrative costs. This means that Energex and Ergon will be required to report different sets of reliability data (MSS and GSL performance data to the QCA and STPIS performance data to the AER).

Energex expressed concern about the potential confusion created by reporting two sets of reliability data.[66] It is important to note that the STPIS and any jurisdictional based average or minimum service standards and GSL schemes are separate regulatory obligations. As such the AER considers that it is necessary for a DNSP to measure and report its service performance against each regulatory obligation irrespective of whether the reporting requirements for those obligations are the same or different. To avoid any confusion the AER expects a prudent DNSP to clearly set out what performance it has measured and reported, to whom and for what purpose that performance is being reported.

Ergon contended that not allowing these exclusions would impose an additional reporting burden and administrative costs on it with no material benefit to users or the AER.[67] While measuring and reporting two sets of reliability data may increase a DNSP's administrative burden and costs it is unlikely that any additional costs will be material.

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64 AER, *Electricity distribution network service providers Service target performance incentive scheme*, Final decision, June 2008, p. 21.
65 NER, note to clause 6.6.2(b)(2).
66 Energex op. cit., p. 8
67 Ergon op. cit., p. 7.

Ergon sought clarification as to whether the MED would be calculated annually to ensure consistency with the EIC. The AER reiterates that the STPIS and any jurisdictional based average or minimum service standards and GSL schemes are separate regulatory obligations. This extends to the MED boundary. Appendix D of the AER's STPIS states that the MED boundary is established at the commencement of the regulatory control period and applies for the duration of the period.[68] Therefore, the distribution determination will, amongst other matters, set out the application of a STPIS including the MED boundary to apply to Energex and Ergon for the duration of the next regulatory control period.

In summary, the AER does not consider it appropriate to allow Energex and Ergon to depart from the national distribution STPIS in order to align the exclusions under the scheme with those in the MSS. In addition, the MED boundary applicable to Energex and Ergon will be established in accordance with the scheme in the distribution determinations and will apply for the duration of the regulatory control period.

2.5.6 Clarifications sought by Energex and Ergon

AER preliminary position

The preliminary position was to apply its national distribution STPIS to Energex and Ergon in the 2010–15 regulatory control period.

Submissions

Energex and Ergon sought a number of clarifications concerning the operation of the national distribution STPIS. These clarifications relate to:

- customers' willingness to pay
- network segmentations
- calculating incentive rates
- the telephone answering parameter
- measuring service performance
- calculating service performance
- the value of the s-factor
- the accumulation of the s-factor
- the s-bank mechanism
- incorporating the s-factor into the control mechanism
- STPIS reporting requirements.

68 AER, *Electricity distribution network service providers Service target performance incentive scheme*, June 2008, p. 30.

AER consideration

The framework and approach paper sets out the AER's likely approach to the application of a STPIS in the forthcoming distribution determination this assists the DNSPs prepare their respective regulatory proposals.

The clarifications sought by the DNSPs relate to the practical operation of the STPIS as distinct from the scheme's general application. Clarification on some operational issues has been provided to the DNSPs and will continue to be discussed as part of pre-lodgement discussions.[69]

2.5.7 Consideration of the National Electricity Rules requirements

The following section sets out the AER's consideration of the NER factors and criteria it must have regard for when implementing a STPIS. Specifically, the AER:

6.6.2(b)(1)—must consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation

The relevant authorities in Queensland are the Queensland Department of Mines and Energy (DME) and the QCA. In arriving at its likely approach to the application of the STPIS, the AER has engaged with both the DME and QCA and invited comments on the preliminary positions paper published on 30 June 2008.

6.6.2(b)(2)—must ensure that service standards and service targets (including (GSL) set by the scheme do not put at risk the DNSP's ability to comply with relevant service standards and service targets (including GSL) as specified in jurisdictional electricity legislation

The STPIS and any jurisdictional based average or minimum service standards and GSL schemes are separate regulatory obligations. The NER envisages the STPIS to operate concurrently with any MSS and GSL schemes that apply to a DNSP under jurisdictional electricity legislation.[70]

As discussed in section 2.5.1, the application of the STPIS will not put at risk Energex's and Ergon's ability to comply with their respective MSS and GSL obligations.

6.6.2(b)(3)(i)—must take into account the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs

The STPIS provides a symmetrical financial incentive for DNSPs to maintain and improve service performance. Customers benefit from the scheme's application by receiving improved service levels or lower prices that reflect diminished service levels. The willingness of customers to pay for improved service levels is reflected in the value of customer reliability (VCR) that applies to reliability of supply parameters

[69] The AER is investigating a concern raised by ETSA Utilities' over the potential perverse outcomes when the service performance in a year is such that the cap on the amount of revenue at risk is invoked. The AER noted in its framework and approach paper for ETSA Utilities that this is not a matter that can be addressed in that paper and the appropriate course is to proceed with consultation on the necessary amendments to the scheme, so that the issues identified can be rectified before the STPIS is applied to DNSPs in their next distribution determinations. This issue is discussed further in the framework and approach paper for ETSA Utilities.

[70] NER, note to clause 6.6.2(b)(2).

and the incentive rate that applies to the telephone answering customer service parameter.

The scheme also allows a DNSP to propose an alternate VCR and/or incentive rate to apply to the telephone answering parameter should it consider the VCR or incentive rate contained in the STPIS does not reflect the willingness of its customers to pay for improved service levels.[71]

The potential penalties and rewards available to Energex and Ergon under the STPIS reflect the benefit to consumers from their service performance.

6.6.2(b)(3)(ii)—must take into account any regulatory obligation or requirement to which the DNSP is subject

Energex's and Ergon's respective MSS and GSL obligations are contained in the EIC. The DNSP's are required to comply with the EIC as a condition of their distribution authorities. The STPIS will operate concurrently with these obligations. As discussed in section 2.5.3, performance targets will be established having regard for Energex's and Ergon's respective MSS obligations.

The EIC requires that the DNSPs operate a GSL scheme. As noted in section 2.5.1 and 2.5.2, consistent with the STPIS the GSL component of the scheme will not apply to Energex and Ergon while the jurisdictional scheme remains in operation.

6.6.2(b)(3)(iii)—must take into account the past performance of the distribution network

Energex's and Ergon's performance targets for the reliability of supply parameters will be established based on their average historical performance having regard for the MSS using the principles set out in section 2.5.3. As discussed in section 2.5.3, the performance targets for the DNSP's telephone answering customer service parameter will also be established based on the average of its historical performance.

6.6.2(b)(3)(iv)—must take into account any other incentives available to the DNSP under the NER or a relevant distribution determination

In their distribution determinations, Energex and Ergon will be subject to the efficiency benefit sharing scheme (EBSS) and the demand management incentive (DMIS).

The EBSS creates incentives for DNSPs to realise operational efficiency gains. The STPIS serves to maintain or, where efficient, improve service levels (where customers are willing to pay for improved service) so that the incentive to minimise opex does not result in lower service levels.

The DMIS creates incentives to implement efficient non-network alternatives. The STPIS is neutral regarding the level of reliability of network and non-network solutions, neither encouraging nor discouraging non-network alternatives relative to augmentation. In this way it sends the same signal to maintain and improve reliability performance whether network or non-network alternatives are adopted.

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[71] AER, *Electricity distribution network service providers Service target performance incentive scheme*, June 2008, clause 3.2.2(d) and 5.3.2, pp. 10 and 15–16.

6.6.2(b)(3)(v)—must take into account the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels

The incentive to reduce costs at the expense of service levels is counterbalanced by the corresponding penalties under the STPIS. The scheme sets out that ± 3 per cent of revenue is sufficient to offset any financial incentive a DNSP has to reduce costs at the expense of service levels.

As discussed in section 2.5.4, the AER considered it reasonable to apply its STPIS to Energex and Ergon with ± 2 per cent of revenue at risk. The AER considers that ± 2 per cent of revenue at risk is sufficient to offset any incentive Energex and Ergon have to reduce costs at the expense of service levels.

6.6.2(b)(3)(vi)—must take into account the willingness of the customer or end user to pay for improved performance in the delivery of services

The willingness of customers to pay for improved levels of service is reflected in the VCR that applies to the reliability of supply parameters and the incentive rate that applies to the telephone answering customer service parameter.

The VCR values contained in the STPIS are based on the findings of a Charles River Associates (CRA) study.[72] The incentive rate for the telephone answering parameter is based on the results of the 2002 survey undertaken in South Australia by KPMG and subsequent analysis by Essential Services Commission of Victoria (ESCV).[73] When developing its STPIS the AER considered that this was the most recent documented and robust work on reliability incentive rates.[74]

The scheme also allows a DNSP to propose an alternate VCR and/or incentive rate to apply to the telephone answering parameter that reflect the willingness of its customers to pay for improved service levels. The AER will assess the appropriateness of any such proposal in making its distribution determination.

6.6.2(b)(3)(vii)—must take into account the possible effects of the scheme on incentives for the implementation of non-network alternatives.

The STPIS's reliability performance measures create a perceived incentive for DNSPs to augment the network rather than implement non-network alternatives such that the incentive to undertake non-network alternatives, such as demand side management initiatives, may be diminished. In the absence of an adjustment to targets or an exclusion to recognise what is seen as a greater risk that targets will not be met.

The scheme remains neutral in its application to network and non-network measures. The AER maintains that the risk associated with non-network alternatives is better placed with a DNSP than with customers. Where aspects of performance are within a DNSP's control, the associated risk should also lie with the DNSP.

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[72] Charles River Associates, *Assessment of the Value of Consumer Reliability (VCR) - report prepared for VENCorp*, 2002.

[73] KPMG, *Consumer preferences for electricity service standards*, 2003. Essential Services Commission, *Electricity Distribution Price Determination 2006–2010 Volume 1*, 2006.

[74] AER, *Electricity distribution network service providers Service target performance incentive scheme*, Final decision, June 2008, p. 17.

11.16.5(1)—take into account the continuing obligations on Energex and Ergon throughout the regulatory control period to implement the recommendations from the EDSD review adopted by the Queensland Government

The central recommendation from the EDSD review was that the Queensland Government mandate minimum service standards for Energex and Ergon. The EDSD review also recommended that the QCA introduce a service quality incentive regime for Energex and Ergon.[75] The application of the STPIS is consistent with the EDSD review recommendations.

11.16.5(2)—take into account the impact of severe weather events on service performance

The STPIS takes into account the impact of severe weather events on service performance by excluding events under the major events day boundary.

Clause 3.2.1(a)(2) and 5.3.1(b)(2) of the scheme provides that performance targets must be modified by any other factors, such as severe weather events, that are expected to materially affect network reliability performance.

11.16.5(3)—consider whether the scheme should be applied by way of a paper trial or whether a lower powered incentive is appropriate.

In section 2.5.4, the AER considered that it is not appropriate to apply the STPIS to Energex and Ergon by way of a paper trial. However, for the reasons set out in section 2.5.4 the AER considered it reasonable to apply the scheme by way of a lower powered incentive with an amount of ± 2 per cent of revenue at risk.

2.6 AER decision

2.6.1 Application of the STPIS to Energex

The AER's likely approach in Energex's forthcoming distribution determination is to apply its national distribution STPIS with ± 2 per cent of revenue at risk. The scheme will operate concurrently with the MSS and GSL jurisdictional obligations contained in the EIC.

Table 2.1 sets out the STPIS components and parameters applicable to Energex in the next regulatory control period. The MAIFI reliability of supply parameter or the streetlight repair, new connections or response to written enquires customer service parameters will not apply. The quality of supply component and the GSL component of the STPIS will not apply to Energex in the next regulatory control period.

Performance targets for the reliability of supply parameters and the telephone answering customer service parameters will be established using the principles set out in section 2.5.3.

Energex will be required to report its service performance to the AER in accordance with any applicable annual regulatory reporting requirements—regulatory information order (RIO).

[75] Detailed report of the Independent Panel: *Electricity Distribution and Service Delivery for the 21st Century*, Queensland, July 2004, p. 57.

Table 2.1: STPIS components and parameters applicable to Energex

Reliability of supply component	
Parameter	***Network segment***
Unplanned SAIDI	CBD
	Urban
	Short rural
Unplanned SAIFI	CBD
	Urban
	Short rural
Customer service component	
Parameter	
Telephone answering	

2.6.2 Application of the STPIS to Ergon

The AER's likely approach in Ergon's forthcoming distribution determination is to apply its national distribution STPIS with ± 2 per cent of revenue at risk. The scheme will operate concurrently with the MSS and GSL jurisdictional obligations contained in the EIC.

Table 2.2 sets out the STPIS components and parameters applicable to Ergon. The MAIFI reliability of supply parameter or the streetlight repair, new connections or response to written enquires customer service parameters will not apply. The quality of supply component and the GSL component of the STPIS will not apply to Ergon in the next regulatory control period.

Performance targets for the reliability of supply parameters and the telephone answering customer service parameters will be established using the principles set out in section 2.5.3.

Ergon will be required to report its service performance to the AER in accordance with any applicable annual regulatory reporting requirements—regulatory information order (RIO).

Table 2.2: STPIS components and parameters applicable to Ergon

Reliability of supply component	
Parameter	***Network segment***
Unplanned SAIDI	Urban
	Short rural
	Long rural
Unplanned SAIFI	Urban
	Short rural
	Long rural
Customer service component	
Parameter	
Telephone answering	

3 Application of an efficiency benefit sharing scheme

3.1 Introduction

This chapter sets out the AER's likely approach, and the reasons for that approach, to the application of an efficiency benefit sharing scheme (EBSS) to be applied to Energex and Ergon in the 2010–15 regulatory control period.

The AER's distribution determinations for Energex and Ergon for the 2010–15 regulatory control period will specify how any applicable EBSS will be applied to these businesses.

3.2 Requirements of the National Electricity Rules

The AER's framework and approach paper must set out its likely approach to the application of an EBSS in a DNSP's forthcoming distribution determination, and the reasons for that approach.[76]

AER's national distribution EBSS

Clause 6.5.8 of the NER requires the AER to develop and publish an EBSS. The EBSS was developed in accordance with the requirements of clause 6.5.8 and the distribution consultation procedures. The scheme and an associated decision document were published on 26 June 2008.[77, 78]

The purpose of the scheme is to provide a fair sharing of efficiency gains and losses between DNSPs and distribution network users.

The EBSS allows a DNSP to retain the benefits of an efficiency gain for the length of the carryover period irrespective of the regulatory year of the regulatory control period in which the gain was initiated. After the carryover period the benefits of an efficiency gain are shared with users through a reduction in the DNSP's forecast opex. The scheme provides a DNSP with a continuous incentive to improve the efficiency of its opex and in doing so to reveal its efficient level of opex.

Carryover amounts are included as a building block element in the calculation of the annual revenue requirement for the regulatory control period following the regulatory control period in which the EBSS was applied.

Implementing the EBSS

Clause 6.5.8(c) of the NER requires that the AER, in implementing an EBSS, must have regard to:

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76 NER, clause 6.8.1(b)(3).

77 AER, *Electricity distribution network service providers Efficiency benefit sharing scheme*, June 2008.

78 AER, *Electricity distribution network service providers Efficiency benefit sharing scheme*, Final decision, June 2008.

- 6.5.8(c)(1)—the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
- 6.5.8(c)(2)—the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure (opex) and, if the scheme extends to capital expenditure (capex), capex
- 6.5.8(c)(3)—the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
- 6.5.8(c)(4)—any incentives that DNSPs may have to capitalise expenditure
- 6.5.8(c)(5)—the possible effects of the scheme on incentives for the implementation of non-network alternatives.

Clause 11.16 of the NER sets out transitional arrangements for Energex's and Ergon's 2010–15 distribution determinations. In particular, when implementing an EBSS under clause 11.16.4:

- 11.16.4(a)—an EBSS for Energex and Ergon for the regulatory control period must not cover efficiency gains and losses relating to capex
- 11.16.4(b)—for the purposes of clause 6.5.8(c) the AER must also have regard to the continuing obligations on Energex and Ergon throughout the regulatory control period to implement the recommendations from the Electricity Distribution and Service Delivery (EDSD) review adopted by the Queensland Government.

3.3 AER preliminary positions

The preliminary position was to apply the national distribution EBSS to Energex and Ergon in the 2010–15 regulatory control period.

3.4 Submissions

Energex and Ergon provided submissions commenting on the positions paper. No other submissions were received. Energex supported the principle of encouraging efficiency gains and of balancing the interests of users and DNSPs. However, Energex requested that the AER clarify its position in relation to uncontrollable ongoing business activities, such as storm response work. It also stated that it remained concerned that the application of symmetrical carryovers did not acknowledge the inherent penalties built into the regulatory framework.

Ergon generally accepted the AER's preliminary position on the application of an EBSS to it but requested that the AER include a suspension clause in the scheme.

3.5 Issues and considerations

The preliminary position on the application of the EBSS to Energex and Ergon had regard to the factors outlined in clause 6.5.8(c) of the NER. This section sets out the AER's consideration of issues raised in submissions on its preliminary positions paper. The AER's consideration of the factors in clause 6.5.8(c) is discussed in section 3.5.4 of this paper.

3.5.1 Exclusion of uncontrollable costs

AER preliminary position

The preliminary position was to apply the national distribution EBSS to Energex and Ergon in the next regulatory control period.

The positions paper noted that the EBSS requires Energex and Ergon to propose in their regulatory proposals any categories of uncontrollable opex to be excluded from the operation of the scheme. It also noted that any proposed uncontrollable cost category needed to be supported by reasons and those categories should not involve ongoing business activity.[79]

Submissions

Energex submitted that it was concerned with the proposal that exclusion from EBSS should not 'involve ongoing business activity'. It stated that its storm response work was an ongoing business activity which is uncontrollable, and that the EBSS allows for uncontrollable opex to be excluded.[80] Energex requested the AER clarify its position in relation to uncontrollable ongoing business activities such as storm response work.[81]

AER consideration

The AER sought additional information from Energex about its storm response work. Energex stated that it has a separate opex cost category called 'emergency response' for storm response work, that this is an ongoing business activity and that all the costs in this category are uncontrollable.[82] Energex stated that its base opex includes costs for emergency work based on an average number of storms per year but the actual frequency and severity of storm events varies significantly from year to year and therefore the costs arising from these events are uncontrollable.[83]

Section 2.3.2 of the EBSS outlines the adjustments to forecast opex allowances for the purpose of calculating carryover amounts. This section states that:

> The AER will permit a DNSP to propose a range of additional cost categories for exclusion from the operation of the EBSS. These categories must be specific to the business, and the DNSP must provide an identifiable reason for exclusion, and should not involve an ongoing business activity. A DNSP must propose cost categories for exclusion from the EBSS in their regulatory

79 ibid., pp. 31–32.
80 Energex, *Response to the AER's Preliminary Positions, Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15,* August 2008, pp. 13–14.
81 ibid.
82 Energex, response to information request, submitted 4 September 2008.
83 ibid.

> proposal prior to the commencement of the regulatory control period during which the EBSS will be applied.
>
> A DNSP must justify a proposal to exclude cost categories to the AER. A DNSP must also not seek to exclude categories of costs that could otherwise be regarded as controllable costs, for example, labour and materials costs and service provider costs. Proposed adjustments to the forecast opex will only be accepted by the AER if they are for changes in costs the AER considers are uncontrollable and will not adversely impact the operation of the EBSS.[84]

The AER's decision on whether Energex's emergency response cost category should be excluded from the EBSS will be made as part of Energex's distribution determination after consultation with interested parties. However, the AER acknowledges that circumstances may exist where an ongoing business activity should be excluded from the operation of the EBSS.

In determining whether a cost category should be excluded from the operation of the EBSS the primary consideration for the AER is whether that cost category is uncontrollable. The AER will have regard to whether the DNSPs proposed cost category is genuinely uncontrollable. The DNSPs will be required to maintain and provide disaggregated opex figures in support of any proposed uncontrollable cost categories to allow proper administration of the EBSS. Outturn opex for uncontrollable cost categories will not be assumed to be efficient for the purposes of forecasting costs for future regulatory control periods, so that the efficiency of base year costs for these categories will need to be established in the DNSPs regulatory proposal.

In accordance with section 2.3.2 of the EBSS, Energex and Ergon should put forward as part of their regulatory proposals cost categories they believe should be excluded from the scheme including the reasons why these costs are considered uncontrollable.

Any exclusions proposed by Energex and Ergon will be reviewed and the opex cost categories considered to be uncontrollable will be listed in the distribution determination for each business. These cost categories will be excluded from the calculation of carryover amounts at the end of the regulatory control period in which the scheme was applied.

In determining the opex cost categories to be excluded from the EBSS that will be applied to Ergon and Energex in their next regulatory control period, the AER's primary consideration will be whether any cost categories put forward by the DNSPs in their regulatory proposals are uncontrollable.

3.5.2 Symmetrical carryovers in the EBSS

AER preliminary position

In the positions paper the assessment of the factors in clause 6.5.8(c) considered that the application of symmetrical carryovers (both positive and negative carryover

84 AER, *Electricity distribution network service providers Efficiency benefit sharing scheme*, June 2008, p. 6.

amounts) in the EBSS was important for the scheme to provide DNSPs with a continuous incentive to improve efficiency.[85]

In the absence of symmetrical carryovers the EBSS will not appropriately reward or penalise DNSPs for improvements or reductions in efficiency.

Submissions

Energex stated that it has residual concerns about the impact of symmetrical carryovers under the EBSS where actual opex is above that forecast.[86] It stated that any opex above the approved opex forecast is funded by the DNSP without receiving any compensation or additional charge to the customer. Energex considers that the DNSP has already incurred a penalty because that additional opex is unfunded and any penalty arising from the EBSS would result in the DNSP effectively being penalised twice.[87]

AER consideration

In developing and implementing an EBSS, the AER must have regard for the factors in clause 6.5.8(c) of the NER. Clause 6.5.8(c)(3) required the AER to consider the desirability of both rewarding DNSPs for efficiency gains and penalising it for efficiency losses.

In developing its EBSS the AER considered it appropriate to include symmetrical carryovers. In its assessment of clause 6.5.8(c)(3) the AER stated that:

> Modelling undertaken of the EBSS highlights that the application of both positive and negative carryovers is necessary for the scheme to provide (DNSPs) a constant incentive to improve efficiency.
>
> Furthermore, without the application of both negative and positive carryover amounts, DNSPs would have a significant incentive to shift opex into the base year of the regulatory control period in order to increase its forecasts for the following regulatory control period. It follows that in the absence of applying both positive and negative carryovers, the EBSS would not in practice provide a DNSP with the incentive to reveal its efficient costs.
>
> The AER accordingly considers it desirable to apply both positive and negative carryovers that reward and penalise DNSPs for efficiency gains and losses incurred respectively.[88]

The scheme does not provide any discretion for the AER to apply either positive or negative carryovers.

Section 2.3.2 of the scheme provides for adjustments to forecast and actual opex for the purpose of calculating efficiency carryover amounts. The inclusion of these adjustments was necessary in order to minimise the risk of negative carryovers resulting from opex variations beyond the DNSPs control.

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85 AER, op. cit., pp. 28–30.
86 Energex, op. cit., p. 14.
87 ibid.
88 AER, *Electricity distribution network service providers Efficiency benefit sharing scheme*, Final decision, June 2008, pp. 19–20.

Opex variations within a DNSPs control that are not adjusted for the purpose of calculating carryover amounts are considered to be efficiency gains or losses under the EBSS and incur a reward or penalty under the scheme.

The purpose of the national distribution EBSS is to provide DNSPs with a continuous incentive to improve the efficiency of its opex and in doing so to reveal its efficient level of opex. If efficiency losses did not attract a financial penalty under the EBSS, the scheme would not provide an adequate incentive for DNSPs to improve opex efficiency. The AER considers that symmetrical carryovers are important to the efficient operation of the scheme.

3.5.3 Inclusion of a suspension clause in the EBSS

AER preliminary position

The preliminary position was to apply its national distribution EBSS to Energex and Ergon in the next regulatory control period.

Submissions

Ergon noted that the national distribution EBSS does not include a provision to suspend the scheme in any circumstances, in contrast to clause 2.7 of the national distribution STPIS which allows the AER to suspend the scheme or a component of the scheme at any time or a DNSP to propose to suspend the scheme or a component of the scheme at any time.[89]

Ergon also noted that EnergyAustralia's regulatory proposal requested that the EBSS be capable of being suspended by agreement with the AER by having all carryover amounts set to zero. Ergon agrees with EnergyAustralia that there may be future situations that may presently be unforeseeable, where it is appropriate to suspend the EBSS in order to avoid perverse or unintended outcomes.[90]

Ergon therefore requested the AER include in its framework and approach paper equivalent provisions for the EBSS as those included in clause 2.7 for the STPIS.[91]

AER consideration

Ergon has not presented any evidence or information relating to future situations or the potential perverse or unintended outcomes that may render it appropriate to suspend the operation of the EBSS, it only referred to a contention made by EnergyAustralia in its regulatory proposal.

Ergon noted that EnergyAustralia had requested that the EBSS be capable of being suspended in order to avoid perverse or unintended outcomes. EnergyAustralia argued that it is unclear 'how the balance and magnitude of sharing will be affected by the setting of efficient operating expenditure allowances in future regulatory periods'.[92] It submitted modelling that it contends 'shows anomalous outcomes under certain

89 Ergon, *Submission to the AER in response to "Preliminary positions – Framework and approach paper – Application of Schemes – Energex and Ergon Energy 2010–15"*, August 2008, p. 11.

90 ibid.
EnergyAustralia, *Regulatory Proposal*, June 2008, pp. 158–159.

91 Ergon, op. cit., p. 11.

92 EnergyAustralia, op. cit., pp 158–159.

conditions'.[93] Consequently, it proposed that the EBSS should allow carryover amounts to be set to zero, that is, suspend the operation of the scheme. In its NSW draft distribution determination the AER will set out its assessment of Energy Australia's contention.

Given the lack supporting information, the AER does not consider it appropriate to depart from its preliminary position. Therefore, it will not include a suspension clause in the EBSS.

3.5.4 Consideration of the National Electricity Rules requirements

The following section sets out the AER's consideration of the NER factors and criteria it must have regard for when implementing an EBSS.

6.5.8(c)(1)—the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs

The EBSS assumes a five year carryover period that produces a sharing ratio of 30:70 between a DNSP and its customers.[94] With the exception of efficiency gains or losses made in the first year of a given five year regulatory control period, efficiency gains and losses in later years of the regulatory control period are carried over (in part) into the following regulatory control period.

Due to the symmetrical nature of the EBSS, a DNSP must share the benefits of its efficiency gains with its customers and incur the costs of its efficiency losses, where these losses are deemed controllable. The risk that customers may incur higher prices due to efficiency losses is mitigated by the continuous incentive for a DNSP to strive for efficiency gains created by the EBSS.

The EBSS provides a constant incentive for a DNSP to improve efficiency. The scheme encourages efficient and timely expenditure throughout the regulatory control period, removing the incentive to only seek efficiency gains in the first half of, or early in, the period. This encourages a DNSP to reveal its efficient opex.

6.5.8(c)(2)—the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex and, if the scheme extends to capex, capex

The EBSS operates to ensure a DNSP does not experience a material advantage in either deferring or advancing opex between regulatory years causing an efficiency gain or loss. Rather, it should represent genuine business outcomes that have arisen in the course of conducting the business in a prudent and diligent manner.

Under the regulatory framework of chapter 6, efficiencies are normally only retained until the end of the regulatory control period. Without an EBSS, a DNSP has the incentive to realise opex efficiencies early in the regulatory control period, so that the benefit of that efficiency can be retained for a longer period of time. By allowing a DNSP to retain the benefit of an efficiency gain for the length of the carryover period (5 years) regardless of the regulatory year in which it is achieved reduces this incentive.

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[93] ibid.

[94] The 30:70 sharing ratio assumes a 6 per cent real discount rate. AER, *Electricity distribution network service providers Efficiency benefit sharing scheme*, Final decision, June 2008, p. 24.

DNSPs also have the incentive to defer opex until the expected base year of the regulatory control period in order to artificially increase forecast opex in the following regulatory control period. It follows that in the absence of applying both positive and negative carryovers, the EBSS would not in practice provide a DNSP with the incentive to reveal its efficient costs. Therefore, as discussed in section 3.5.2, through the application of symmetrical carryovers, the EBSS provides a DNSP with a continuous incentive to improve efficiency.

6.5.8(c)(3)—the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses

Modelling of the EBSS demonstrated that application of positive and negative carryovers is necessary to provide DNSPs a continuous incentive to improve efficiency. As noted in section 3.5.2, in the absence of symmetrical carryovers, there is a perceived incentive to shift opex into the expected base year in order to increase forecast opex in the forthcoming regulatory control period.

Any negative or positive carryover amount will be included as a building block element in the calculation of the DNSPs allowed revenue in the following regulatory control period. Efficiency gains and losses are treated equally, to ensure that the incentives created by the EBSS are not skewed in favour of realising opex efficiencies.

6.5.8(c)(4)—any incentives that DNSPs may have to capitalise expenditure

To negate any incentive a DNSP may have to capitalise expenditure where it is inappropriate to do so, the EBSS requires that forecast opex figures used to calculate carryover amounts be adjusted to account for any changes to that DNSPs capitalisation policy.

6.5.8(c)(5)—the possible effects of the scheme on incentives for the implementation of non-network alternatives.

Expenditure on non-network alternatives generally takes the form of opex, rather than capex. The EBSS does not apply to capex, therefore the incentive later in the regulatory period to reduce capex is less than the incentive to reduce opex. Therefore, a DNSP may have a greater incentive to augment its network later in the regulatory control period than to implement non-network alternatives that incur opex.

The EBSS excludes all opex associated with non-network alternatives. This removes the potential impact of the scheme, which may otherwise discourage DNSPs from considering demand management initiatives.

11.16.4(a)—an EBSS for Energex and Ergon for the regulatory control period must not cover efficiency gains and losses relating to capex

The national distribution EBSS does not include efficiency gains or losses that relate to capex.

11.16.4(b)—for the purposes of clause 6.5.8(c) the AER must also have regard to the continuing obligations on Energex and Ergon throughout the regulatory control period to implement the recommendations from the EDSD review adopted by the Queensland Government.

The EDSD review recommended that Energex and Ergon increase the preventative maintenance on their networks from that carried out prior to 2004.

There may be concerns in applying an EBSS to DNSPs that have been consistently underspending opex. This concern is no longer applicable in Queensland. The most recent QCA data indicates that Energex and Ergon have overspent opex in the first two years of the current regulatory period.[95, 96] It is therefore appropriate to apply an EBSS to Energex and Ergon in the next regulatory control period.

Applying a STPIS in conjunction with an EBSS addresses the key concern raised by the EDSD review relating to an inadequate regulatory framework.

3.6 AER decision

3.6.1 Application of the EBSS to Energex

Pursuant to clauses 6.8.1, 6.5.8(c) and 11.16.4 of the NER, the AER has determined that its likely approach to the application of an EBSS to Energex for the forthcoming distribution determination is to apply its national distribution EBSS to Energex.

3.6.2 Application of the EBSS to Ergon

Pursuant to clauses 6.8.1, 6.5.8(c) and 11.16.4 of the NER, the AER has determined that its likely approach to the application of an EBSS to Ergon for the forthcoming distribution determination is to apply its national distribution EBSS to Ergon.

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95 QCA, *Financial and Service Quality Performance 2006–07 Energex*, March 2008, p. 4.
QCA, *Financial and Service Quality Performance 2005–06 Energex*, March 2007, p. 4.

96 QCA, *Financial and Service Quality Performance 2006–07 Ergon Energy*, March 2008, p. 4.
QCA, *Financial and Service Quality Performance 2005–06 Ergon Energy*, March 2007, p. 4.

4 Application of a demand management incentive scheme

4.1 Introduction

This chapter sets out the AER's likely approach to the application of a demand management incentive scheme (DMIS) to be applied to Energex and Ergon and its reasons for that approach.

The capex and opex objectives in chapter 6 of the NER require DNSPs to meet or manage the demand for standard control services. Demand management refers to measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services rather than increasing supply.

The objective of the DMIS is to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way.[97] The DMIS operates in conjunction with existing incentives in the regulatory framework to pursue these objectives.

4.2 Requirements of the National Electricity Rules

The AER's distribution determination for Energex and Ergon for the 2010-15 regulatory control period must specify how a DMIS will be applied in that regulatory period.[98] In its framework and approach paper for Energex and Ergon, the AER must set out its likely approach, together with the reasons for that approach, to the application of a DMIS in its forthcoming distribution determination.[99]

AER's distribution DMIS for Queensland and South Australian DNSPs

Clause 6.6.3 of the NER allows the AER to develop and publish a DMIS. The DMIS was developed in accordance with the requirements of clause 6.6.3 and the distribution consultation procedures and will apply to Energex, Ergon and ETSA Utilities in the regulatory control periods commencing on 1 July 2010. The scheme and an associated decision document were published on 17 October 2008.[100, 101]

Structure of the DMIS for Queensland and South Australian DNSPs

The DMIS consists of two parts:

Part A: Demand management innovation allowance

The demand management innovation allowance (DMIA) allows the recovery of costs of demand management projects and programs throughout the regulatory control period, subject to satisfaction of defined criteria. The DMIA is provided as a capped, annual ex ante allowance.

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[97] NER, clause 6.6.3(a).

[98] NER, clause 6.3.2(a)(3).

[99] NER, clause 6.8.1(b)(4).

[100] AER, *Demand Management Incentive Scheme Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

[101] AER, *Demand Management Incentive Scheme Energex, Ergon Energy and ETSA Utilities 2010–15*, Final decision, October 2008.

The DMIA is subject to an adjustment to return to end users any expenditure not approved by the AER and/or any underspend. Any underspend accumulated at the end of the relevant regulatory control period will not be carried over but will be recovered in the subsequent regulatory control period. Further, the adjustment at the end of the relevant regulatory period will account for the time value of money to render the scheme insensitive to expenditure profiles over that period. These adjustments will be done in the second year of the subsequent regulatory period as a single adjustment.

Annual reporting requirements provide transparency in the operation of the DMIA, and allow the AER, DNSPs, end users and other stakeholders to monitor the effectiveness and outcomes of the scheme.

Part B: Recovery of forgone revenue

Part B of the DMIS allows recovery of revenue forgone by a DNSP within the relevant regulatory control period as a result of a reduction in the quantity of electricity sold due to the implementation of non-tariff demand management projects and programs approved under the DMIA. Part B will only apply to a DNSP where the form of control that applies to its standard control services results in its approved regulated revenue for those services being dependent on the quantity of energy actually sold.

Recovery of forgone revenue is in addition to the capped amount of the DMIA. However, the actual recoverable amount is limited to revenue forgone resulting from a reduction in the quantity of electricity sold that is directly attributable to a project established under part A of the scheme. The forgone revenue will be provided in the subsequent regulatory control period, at the same time as the adjustments under the DMIA mentioned above.

Implementing the DMIS

Clause 6.6.3 of the NER requires that the AER, in developing and implementing a DMIS, must have regard to:

- 6.6.3(b)(1)—the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSP
- 6.6.3(b)(2)—the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a DNSP's incentives to adopt or implement efficient non-network alternatives
- 6.6.3(b)(3)—the extent the DNSP is able to offer efficient pricing structures
- 6.6.3(b)(4)—the possible interaction between a demand management incentive scheme and other incentive schemes
- 6.6.3(b)(5)—the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

The NER does not contain any transitional arrangements that relate to the application of a DMIS to Energex and Ergon in the next regulatory control period.

4.3 AER preliminary positions

The preliminary position on the application of a DMIS to Energex and Ergon was based on the proposed DMIS developed for Queensland and South Australia.[102] The proposed DMIS was published on the 30 June 2008 at the same time as the preliminary positions paper.[103] That scheme included the DMIA in Part A of the final scheme, but not the forgone revenue component in part B.

The preliminary position was that it was likely to apply a DMIS in the form of an ex ante DMIA to Energex and Ergon for the 2010-15 regulatory control period. The allowance was capped at a total of $5 million over the regulatory control period, nominally allocated in five equal annual instalments of $1 million. This allowance was to be provided in addition to any opex and capex allowances for demand management projects included within the AER's distribution determination for Energex and Ergon.

4.4 Submissions

Energex and Ergon provided submissions commenting on the positions paper. No other submissions were received. The main issues raised in submissions were in relation to:[104, 105]

- the amount of the DMIA
- ex-post assessment and the treatment of unapproved demand management expenditure under the efficiency benefit sharing scheme (EBSS)
- the administrative cost of the ex post review of demand management expenditure.

4.5 Issues and considerations

The preliminary position on the application of the DMIS to Energex and Ergon had regard to the factors outlined in clause 6.6.3 of the NER. This section sets out the AER's consideration of issues raised in submissions on its preliminary positions paper. The AER's consideration of the factors in clause 6.6.3 is discussed in section 4.5.4 of this paper.

The final DMIS for DNSPs in Queensland and South Australia, published on 17 October 2008 and described in section 4.2 above, is largely consistent with the proposed DMIS released 30 June 2008. The key differences are:

- refinements to the approval criteria and reporting requirements (part A of the DMIS)

102 AER, *Framework and approach paper—Application of schemes Energex and Ergon Energy 2010–15*, Preliminary positions, June 2008.

103 AER, *Proposed demand management incentive scheme for Energex, Ergon Energy and ETSA Utilities for the 2010–15 regulatory control period*, June 2008.

104 Energex, *Response to the AER's Preliminary Positions, Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15,* August 2008, pp. 15–16.

105 Ergon, *Submission to the AER in response to "Preliminary positions – Framework and approach paper – Application of Schemes – Energex and Ergon Energy 2010–15"*, August 2008, p. 11.

- the incorporation of a forgone revenue mechanism (part B of the DMIS).

The NER allows for different control mechanisms to be applied to different DNSPs. The AER decided to apply a fixed revenue cap form of control to Energex's and Ergon's standard control services.[106] The AER recognises that under forms of control where the amount of approved regulated revenue is at least partially dependant on the quantity of electricity sold (i.e. a weighted average price cap) a successful demand management program that causes a reduction in demand may result in less revenue to a DNSP. This means that the DNSP has a disincentive to reduce electricity sales.

The AER does not consider that the form of control (revenue cap) applicable to Energex and Ergon during the next regulatory control period has a disincentive to reduce electricity as approved regulated revenues are not dependant on quantity of electricity sold. Therefore, it is not necessary to apply part B of the DMIS to Energex and Ergon.

4.5.1 The amount of the demand management innovation allowance

AER preliminary position

The preliminary position was to apply its proposed DMIS in the form of a DMIA to Energex and Ergon in the 2010–15 regulatory control period. The allowance was capped at a total of $5 million over the regulatory control period, nominally allocated in five equal annual instalments of $1 million.

Submissions

Energex recognised that the DMIA will need to be capped on an ex-ante basis but requested that mechanisms be incorporated that will enable an increase to the allowance to encourage innovation to continue during the regulatory period should the available opportunities exceed the initial limit. Ergon also submitted that the AER should consider the sufficiency of the allowance.

AER consideration

The preliminary positions paper stated that the DMIA will be capped at an amount that is broadly proportionate to the size of the DNSP's annual revenue requirement in the previous regulatory period. It noted that this approach was consistent with that taken in the development of the innovation allowance for DNSPs in the ACT and NSW determinations, in that the allowance for Energex and Ergon will be proportionate to that given to DNSPs of comparable size in other jurisdictions.

Although, Energex and Ergon have raised the issue of sufficiency of the allowance, neither have proposed an alternative allowance nor provided evidence to support a potential shortfall in the allowance of $5 million set out in the preliminary position paper.

The modest, use-it-or-lose it nature of the DMIA is appropriate given its broad scope and focus on innovation. Further, when regard is had to the long-term nature of expected benefits to consumers from the scheme, and the limited information

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[106] AER, *Framework and approach paper—Classification of services and control mechanisms Energex and Ergon Energy 2010–15*, August 2008.

available on customer willingness to pay for increases in costs resulting from the implementation of a DMIS, the AER is not satisfied that an increase to the DMIA is appropriate at this time. An increased allowance would require a corresponding increase in prescription in the scheme's application, which would impose constraints on the use of the DMIA that are contrary to the scheme's objectives.

The DMIA is not intended to be the only source of cost recovery for demand management expenditure. It is appropriate that a DNSP recover demand management costs primarily through forecast opex and capex approved at the time of the distribution determination, so that recovery through regulated revenues of amounts in excess of that contemplated by the DMIA is subject to the more rigorous ex-ante assessment.

The DMIA is designed to supplement a DNSP's approved capex and opex, to facilitate investigation and implementation of demand management strategies which, where they prove viable, will allow DNSPs to implement non-network alternatives where efficient, and to manage the expected demand for standard control services through means other than network augmentation.

Given that the DMIA is broadly proportionate to previous annual revenue requirements, the long term nature of expected benefits and the limited information available on customer willingness to pay the AER does not consider it necessary to include a mechanism to adjust the size of the allowance during the regulatory period.

The AER's likely approach is to apply an allowance of $5m ($1 million per annum) to Energex and Ergon individually in the forthcoming regulatory control period and will not include a mechanism to enable an increase during the regulatory period.

4.5.2 Ex-post assessment and EBSS

AER preliminary position

The proposed DMIS, stated that expenditure under the DMIA will be assessed on an annual basis, against criteria established under the scheme. It also noted that while the allowance will be made available on an ex ante basis, only approved expenditure will be deemed recoverable. The preliminary position was to apply the proposed DMIS to Energex and Ergon.

The preliminary position paper noted that to minimise the impact of the EBSS on the incentive to undertake efficient demand management programs, the EBSS excludes costs associated with demand management from the calculation of opex overspends and underspends.

Submissions

Energex submitted that the requirement for an ex-post assessment of the demand management expenditure effectively transfers the risks to the DNSP. It noted that if undertaken in 'good faith' then such expenditure should be funded from the allowance. It was also concerned on how the disallowed expenditure (based on ex-post review) would be treated under the EBSS.

AER consideration

The transfer of risk to the DNSP will occur only if the ex-post review results in non approval of expenditure undertaken by the DNSP. The final DMIS has provided further clarity on the types of demand management initiatives recoverable under the allowance and expanded upon the criteria.[107] These expanded approval criteria will provide Energex and Ergon with greater certainty as to what costs will be approved and enable it to reasonably manage any potential risk transfer. Further, if sufficient consideration is given to these expanded criteria at the time of undertaking the expenditure then the AER believes that the risk of non-approval is limited and the question of 'good faith' will not arise.

The DMIS clarified the position in relation to the interaction of the EBSS and the DMIS.[108] Consistent with that position, demand management expenditure submitted for approval under the DMIS, but rejected on the basis that it does not relate to demand management projects or programs in accordance with the DMIA criteria, will not be recognised as demand management expenditure. However, if that expenditure can be otherwise attributed to non-network alternatives, it will be excluded from the operation of the EBSS. But if it cannot be so attributed then such expenditure will not be excluded from the EBSS.

The expanded approval criteria significantly reduce the risk to the DNSPs that demand management expenditure under the DMIA will not be approved. Although, expenditure is not approved under the DMIA if that expenditure can be otherwise attributed to non-network alternatives, it will be excluded from the operation of the EBSS

4.5.3 Administrative cost of the ex-post review

AER preliminary position

The preliminary position was to apply the DMIA approval methodology as set out in its proposed DMIS. The approval methodology in the proposed DMIS included an annual assessment of the expenditure on an ex post basis and a single adjustment in the subsequent regulatory period to account for underspends or amounts not approved. Ex post adjustments were not to be made within the relevant regulatory period.

Submissions

Energex submitted that any benefits of the scheme will be consumed by the disproportionate administrative costs due to the onerous requirements of the ex-post review.[109] Ergon also stated that the costs of the ex-post review may be disproportionate to the DMIA.[110]

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[107] AER, *Demand Management Incentive Scheme Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008, pp. 5–6..

[108] AER, *Demand Management Incentive Scheme Energex, Ergon Energy and ETSA Utilities 2010–15,* Final decision, October 2008, p. 6.

[109] Energex op. cit., p. 16.

[110] Ergon op. cit., p. 11.

AER consideration

Energex stated that one of the key considerations that the AER must have regard to is the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme.[111]

The AER recognises that the operation of the DMIS may result in cost impacts within a regulatory period where benefits are unlikely to be revealed until later periods. However, the DMIS encourages the implementation of demand management initiatives which provide long term efficiency gains to energy users that are expected to outweigh any short term price increases.

Currently, the information available on customer willingness to pay for increases in costs resulting from implementing demand management initiatives is limited. However, the DMIS is a modest scheme, provided on a use-it-or-lose-it basis and resulting increases in customer prices are expected to be minimal. Therefore, although the benefits to customers likely to result from the scheme cannot be directly assessed at this stage, the AER considers that given the modest nature of the scheme the associated costs are appropriate.

The DMIS is based on an ex-ante allowance with an annual approval mechanism. The reporting requirements are a necessary component of the DMIS. These annual reports will form the basis of the AER's assessment of the DNSP's compliance with the DMIA criteria and also inform whether it is entitled to recover expenditure under the DMIA. The final DMIS considered stakeholder comments on the appropriateness of the reporting requirements. It stated that the reporting requirements are necessary for the assessment and are not disproportionate to the expected benefits and costs of the scheme.[112]

Generally, a DNSP that undertakes demand management initiatives will apply good business practices such as identifying the scope of the project and expected outcomes, keeping proper records of the initiative and expenditure as well as setting out methodologies for evaluating outcomes against objectives. Expenditure associated with such activities would be normal in the course of business. The AER does not consider that the ex-post review under the DMIS has imposed any other onerous requirements.

The AER does not consider the annual reporting costs to be disproportionate to the likely benefits. Consistent with its preliminary position the ex-post assessment methodology as set out in the DMIS to approve expenditure under the DMIA will be applied.

4.5.4 Consideration of the National Electricity Rules requirements

The following section sets out the AER's consideration of the NER factors and criteria it must have regard for when implementing a DMIS.

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[111] NER, clause 6.6.3(b)(1).

[112] AER, *Demand Management Incentive Scheme Energex, Ergon Energy and ETSA Utilities, 2010–15*, Final decision, October 2008, pp. 12–13.

6.6.3(b)(1)—the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs

The rewards and penalties payable under a DMIS must be set at a level that ensures that the costs to consumers resulting from the associated adjustment to regulated revenues do not exceed the benefits expected to result from the implementation of the DMIS. In striking the appropriate balance, it must be recognised that the operation of such a scheme may result in cost impacts within a regulatory period where benefits are unlikely to be revealed until later periods.

The DMIS encourages the implementation of demand management initiatives which provide long term efficiency gains to energy users that are expected to outweigh any short term price increases. The allowance is designed to provide incentives for DNSPs to conduct efficient, broad-based and/or innovative demand management programs, and should coordinate well with both existing and potential demand management initiatives being carried out by Energex and Ergon in the current regulatory period. Due to rising demand in Queensland, a broad-based scheme that targets general demand reduction and encourages efficient energy use across the distribution network, rather than specific areas may be appropriate.

Given that peak demand is a key driver of network capital expenditure, a DMIS could also be used for initiatives which result in a more efficient use of existing infrastructure and a lower level of investment in new infrastructure through either deferral of, or removal of the need for, network augmentation and/or expansion expenditures.

The DNSP's submissions on the sufficiency of the DMIA and the need to allow for a mechanism to adjust the size of the allowance during the regulatory control period have been considered in section 4.5.1. For the reasons set out in that section the AER does not consider it necessary to change the DMIA as stated in its preliminary positions paper.

For the reasons set out in section 4.5.3, the AER considers that the administrative costs associated with implementing the scheme are consistent with the benefits to consumers.

6.6.3(b)(2)—the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a DNSP's incentives to adopt or implement efficient non-network alternatives

In applying the DMIS, the AER has had regard to the effects that particular control mechanisms may have on the incentives or disincentives for DNSPs to undertake demand management. The AER accepts that incentives for demand management may be affected by the control mechanism applied to a DNSP's standard control services. Under forms of control where revenue is at least partially dependent on the quantity of electricity sold (e.g. a price cap), a successful demand management program that causes a reduction in demand may result in less revenue to a DNSP.

The AER's decided to apply a fixed revenue cap form of control to Energex's and Ergon's standard control services.[113]

The AER does not consider that the form of control (revenue cap) applicable to Energex and Ergon during the next regulatory control period has a disincentive to reduce the quantity of electricity as approved regulated revenues are not dependant on quantity of electricity sold.

6.6.3(b)(3)—the extent the DNSP is able to offer efficient pricing structures

Ideally, efficient pricing structures exist where the price of electricity at a particular point in the network reflects the true costs of its supply at that location at a particular point in time. For instance, efficient pricing structures should reflect increases in costs of supplying electricity in times of peak demand.

The AER considers that there is scope within the current regulatory arrangements for Energex and Ergon to provide efficient pricing structures, for instance, in the application of peak tariffs or time-of-use tariffs for large customers. However, the ability to influence small customer demand through pricing structures is limited in jurisdictions where efficient price signals are impeded by retail tariff bundling or price controls. The national roll-out of smart meters to be considered by the Council of Australian Governments will allow price signals to reach small customers.

Whilst noting that regulated tariffs are applicable to small customers, full retail contestability has been introduced in Queensland. The AER is aware that some small customers have taken up market contracts and could make use of available efficient pricing structures.

The AER considers that the application of the DMIA will provide incentives for Energex and Ergon to trial tariff-based demand management programs which will provide further information on mechanisms for efficient pricing.

6.6.3(b)(4)—the possible interaction between a DMIS and other incentive schemes

In applying a DMIS to Energex and Ergon the AER must have regard to the interaction of that scheme with other incentive schemes. As outlined in chapters two and three of this paper, the AER's likely approach is that both an EBSS and STPIS will be applied to Energex and Ergon in the 2010-15 regulatory control period.

Increased expenditure on demand management within the regulatory control period may increase opex above the levels forecast in the distribution determination. This could lead to a corresponding and unintended penalty under the EBSS. To minimise the impact of the EBSS on the incentives to undertake efficient demand management programs, the EBSS excludes all costs associated with non-network alternatives including opex spent under the DMIS from the calculation of opex overspends and underspends. This removes the potential impact of the EBSS on the incentive created by the DMIS to develop and implement demand side management in response to network issues.

113 AER, *Framework and approach paper—Classification of services and control mechanisms Energex and Ergon Energy 2010–15*, August 2008.

The AER's expanded approval criteria, as discussed in section 4.5.2 and set out in the DMIS, has clarified concerns relating to the interaction of the EBSS with any disallowed expenditure under the DMIS.

There is a perceived disincentive to implement non-network alternatives to augmentation created by the reliability performance measures in its STPIS, such that incentives to undertake demand side management may be diminished by what is seen as a greater risk that targets will not be met. The DMIS is designed to facilitate improved demand management capability and capacity, and to promote innovative and new developments in the area of demand management so that demand management projects may increasingly be identified as viable alternatives to network augmentation. This feature of the DMIA is designed to break down the barriers to implementation of demand management solutions arising from DNSP's claims that such options remain largely unproven and reflect a higher risk than network-based solutions in the context of service incentive schemes and community expectations.

The AER considers that the application of the DMIS to Energex and Ergon will not negatively interact with the incentives created by other incentive schemes or send conflicting signals in terms of desired expenditure outcomes.

6.6.3(b)(5)—the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

The costs associated with the application of the proposed demand management innovation allowance to Energex and Ergon should be commensurate with the value that the DNSPs' customers, or end users, attach to demand management. While the AER understands that customers are in principle supportive of demand management initiatives, little is known about their willingness to pay.

The AER considers that the application of its proposed DMIS is appropriate in light of the limited information available to date on customer willingness to pay for demand management, as the scheme provides a modest, capped allowance for demand management initiatives and is unlikely to result in large increases in customers' prices.

4.6 AER decision

4.6.1 Application of the DMIS to Energex

Having had regard to submissions in response to the preliminary positions paper and the requirements of the NER, the AER's likely approach is to only apply part A of the DMIS to Energex in the 2010-15 regulatory control period.

The AER's decided to apply a fixed revenue cap control mechanism to Energex's standard control services. This form of control does not create any disincentives for Energex to adopt or implement efficient non-network alternatives, in that a reduction in the quantity of electricity sold will not result in a reduction in revenue. Therefore, part B of the DMIS will not apply as it relates to circumstances where the control mechanism results in foregone revenues due demand management initiatives.

The DMIA will be capped at a total of $5 million over the forthcoming regulatory control period, nominally allocated in five equal annual instalments of $1 million.

This allowance will enable Energex to carry out a number of small-scale demand management projects, or a single larger-scale demand management project, in each year of the forthcoming regulatory control period.

4.6.2 Application of the DMIS to Ergon

Having had regard to submissions in response to the preliminary positions paper and the requirements of the NER, the AER's likely approach is to only apply part A of the DMIS to Ergon in the 2010-15 regulatory control period.

The AER's decided to apply a fixed revenue cap control mechanism to Ergon's standard control services. This form of control does not create any disincentives for Ergon to adopt or implement efficient non-network alternatives, in that a reduction in the quantity of electricity sold will not result in a reduction in revenue. Therefore, part B of the DMIS will not apply as it relates to circumstances where the control mechanism results in foregone revenues due demand management initiatives.

The DMIA will be capped at a total of $5 million over the forthcoming regulatory control period, nominally allocated in five equal annual instalments of $1 million. This allowance will enable Ergon to carry out a number of small-scale demand management projects, or a single larger-scale demand management project, in each year of the forthcoming regulatory control period.

5 Other matters

5.1 Introduction

The preliminary positions paper did not identify any 'other matters'.[114] The NER allows the AER to set out in its framework and approach paper its likely approach to any other matter on which it thinks fit to give an indication.

In response to the preliminary positions paper both Energex and Ergon submitted 'other matters' that they considered the AER should indicate its likely approach on. Energex raised the following four 'other matters':

- cost pass through materiality threshold
- cost pass through for input cost increases
- cost pass through for alternative control services
- application of security of supply standards.[115]

Ergon raised the following 11 'other matters' (which included the above matters raised by Energex):

- negotiating framework
- Mt Isa – Cloncurry network
- asset categories
- asset lives
- regulatory asset value
- no prudency review
- cost pass through for input cost increases
- cost pass through materiality threshold
- cost pass through for alternative control services
- eligible pass through amount, information requirements and process
- application of security of supply standards. [116]

114 AER, *Framework and approach paper—Application of* schemes *Energex and Ergon Energy 2010–15*, Preliminary positions, June 2008.

115 Energex, *Response to the AER's Preliminary Positions, Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15,* August 2008, pp. 18–20.

116 Ergon, *Submission to the AER in response to "Preliminary positions – Framework and approach paper – Application of Schemes – Energex and Ergon Energy 2010–15"*, August 2008, pp. 12–20.

This chapter sets out the AER's likely approach on the 'other matters' it thinks fit to provide an indication of its likely approach and the reasons for that likely approach.

5.1.1 Requirements of the National Electricity Rules

In addition to the components required under the NER, the AER can set out in its framework and approach paper its likely approach (together with its reasons for the likely approach) to any other matter on which it thinks fit to give such an indication.[117]

Clause 6.8.1(b) of the NER states that:

> The framework and approach paper should set out the AER's likely approach (together with its reasons for its likely approach), in the forthcoming distribution determination, to:
>
> …
>
> (5) any other matters on which the AER thinks fit to give an indication of its likely approach.

Clause 6.8.1(b)(5) provides the AER with discretion about the matters that it will set out its likely approach beyond the other matters specified in clause 6.8.1(b).

5.2 Issues and considerations

While the AER recognises the need to provide the DNSPs with an indication of its likely approach to assist them in preparing their regulatory proposals, it does not consider it necessary or appropriate to address matters in the framework and approach paper that are:

- more appropriately confined to the assessment of the DNSP's regulatory proposal
- not relevant to the development of the DNSP's regulatory proposal
- more appropriately addressed via normal pre-lodgement discussion processes.

5.2.1 Negotiating framework

Submissions

Ergon submitted that its regulatory proposal need not include a negotiating framework where there was no negotiated distribution service proposed.

AER consideration

The framework and approach paper on classification of services and control mechanisms for the Queensland DNSPs did not classify any services as negotiated distribution services.[118]

[117] NER, clause 6.8.1(b)(5).

[118] AER, *Framework and approach paper—classification of services and control mechanisms,* Energex and Ergon Energy 2010–15, August 2008.

A DNSP is not required to submit a negotiating framework in its regulatory proposal where it does not provide negotiated distribution services. However, the draft determination can decide that certain services should be classified as negotiated distribution services, even though the DNSP did not propose any negotiated distribution services. In such circumstances the AER will notify the DNSP of the change of classification in its draft determination and require it to submit a negotiating framework as part of its revised regulatory proposal.[119]

A dispute between a DNSP and a person who seeks access to a distribution service, about the terms and conditions of access to standard control distribution services and alternative control distribution services will be an access dispute under the NEL (a dispute about the terms and conditions of access to negotiated services will also be an access dispute under the NEL). Such access disputes are subject to dispute resolution under part L of the NER.

AER decision

Ergon is not required to include a negotiating framework in the absence of any service being proposed as a negotiated distribution service.

5.2.2 Mt Isa – Cloncurry network

Submissions

Ergon submitted that it owns and operates the Mt Isa – Cloncurry isolated distribution network and that this network is currently regulated by the QCA as directed by the relevant Minister under the *Electricity Act 1994* (Qld). Ergon advised that the Queensland Government is considering the transfer of responsibility for regulating this isolated network from the QCA to the AER. It noted that the Queensland Government may not finalise the transfer of regulatory responsibility prior to Ergon's deadline for submitting the regulatory proposal to the AER. Therefore, Ergon requested that the AER provide in-principle agreement:

- for the inclusion of this isolated network in its regulatory proposal
- that the AER will assess the proposal in accordance with chapter 6 of the NER
- that the AER's distribution determination provide for either inclusion or exclusion of the Mt Isa – Cloncurry network from the determination once the Queensland Government's future regulatory treatment of this network is known.[120]

The QCA's 2005 distribution determination for Ergon included the Mt Isa – Cloncurry isolated distribution network.

AER consideration

The AER was informed by the Queensland Government that it intends transferring the regulatory responsibility for this network to the AER as permitted by the Australian

[119] NER, clause 6.10.3(b).
[120] Ergon, op. cit., pp. 14–15.

Energy Market Agreement and that this process is expected to be finalised prior to 31 May 2009.[121]

Ergon is entitled to include this isolated network in its regulatory proposal. The AER is bound to apply the law and rules in force as at the time of assessing the regulatory proposal. Therefore, the inclusion or exclusion of the Mt Isa – Cloncurry network in the distribution determination (2010–15) will depend on whether the required legislative changes transferring the regulatory functions to the AER are in place by the regulatory proposal due date (31 May 2009).

AER decision

The AER will assess Ergon's regulatory proposal in accordance with the applicable law and rules as at 31 May 2009.

5.2.3 Asset categories and asset lives

Submissions

Ergon sought confirmation from the AER that it is acceptable to use the asset classes it currently reports to the QCA in its regulatory accounts. Ergon noted that the asset classes used in the QCA's 2005 determination were different to those used by Ergon in its annual regulatory accounts. Further, Ergon noted that if street lighting was classified other than as a standard control service then it will not include a street lighting asset category in the roll forward model (RFM) or the post tax revenue model (PTRM).

Ergon submitted that it has to devise a method for determining the remaining asset life values because the AER has not outlined a particular method for devising remaining useful lives and that the QCA had not used asset classes or tax asset lives for the 2005 distribution determination. Ergon requests that the AER confirm its agreement to the following proposed methodology for the treatment of the remaining asset lives in its regulatory proposal:

- Asset standard lives for each asset class should be provided consistent with the asset classes in the annual regulatory reports to the QCA.
- Tax standard lives for each asset class should be provided in accordance with the Australian Taxation Office (ATO) determinations.
- Asset remaining lives for each asset class correct as at 1 July 2005 should be provided based on the asset lives in Ergon's asset register adjusted to reflect the asset classes in the 2005-06 regulatory accounts.
- Asset remaining lives for each asset class correct as at 1 July 2010 should be calculated by Ergon based on the forecast mix of assets as of that date and the method of calculation detailed in the regulatory proposal.

[121] Department of Mines and Energy, letter to the Chairman AER dated 21 October 2008.

- Tax remaining lives for each asset class correct as at 1 July 2005 should be provided based on the tax lives in Ergon's tax book and these should be disclosed in the regulatory proposal.

- Tax remaining lives for each asset class correct as at 1 July 2010 should be calculated by Ergon based on the forecast mix of assets as of that date and the method of calculation detailed in the regulatory proposal.[122]

AER consideration

Ergon's submission relates to three specific areas:

- changing asset categories and calculating remaining asset lives

- calculating the tax asset base and remaining tax lives

- treatment of street lighting assets.

Changing asset categories and calculating remaining asset lives

The issues associated with changing asset categories have implications for the RFM and PTRM. Such changes could impact the calculation of depreciation, opening asset values and rolling forward actual capital expenditure (capex) from the current regulatory period. Any change over from the historical asset category to a new category would require the DNSPs to provide reconciliations across the old and new categories to ensure that depreciation is correctly calculated. Further, the integrity of the opening asset base and the RFM will need to be ensured.

Ergon's request for approval relates only to its proposed methodology. However, given the implications mentioned above, the methodology cannot be approved on a stand-alone basis without verifying the reasonableness of underlying supporting data and the output values. Ergon's asset categories and remaining asset lives including the methodology used to change categories will be reviewed at the time of making the distribution determination in consultation with interested parties.

Nevertheless, the AER will assist Ergon by providing feedback via the on-going pre-lodgement discussions on the level of verification and information required from it to confirm that there are no adverse consequences due to the implications mentioned above.

AER decision

The AER will liaise with the Ergon on establishing a methodology for changing asset categories and calculating remaining asset lives but considers it inappropriate to commit to an approach that determines values outside of the distribution determination process.

Calculating the tax asset base and remaining tax lives

Under the post-tax approach to regulation, Ergon will be required to provide the AER its tax asset base and remaining tax lives to calculate its tax liabilities. This

[122] Ergon, op. cit., pp. 12–13.

information is required for the PTRM. Ergon has not previously provided the QCA its tax asset base as part of the regulatory proposal.

Ergon's request for approval relates only to its proposed methodology. However, the methodology cannot be approved on a stand-alone basis without ensuring that the appropriate initial asset values have been incorporated in the tax asset base and are verifiable by supporting documents. In the absence of a review of the supporting documents the AER is not in a position to endorse a particular methodology. Ergon's tax asset base and remaining tax asset lives will be reviewed as part of the distribution determination in consultation with interested parties.

As noted before, the AER will provide feedback via the pre-lodgement discussions to inform Ergon of the level of verification and information required from it to support its tax asset base and remaining tax asset lives proposal.

AER decision

The AER considers it inappropriate to indicate its likely approach on a methodology for calculating the tax asset base and remaining tax lives at the framework and approach stage.

Treatment of street lighting assets

Ergon's submission which included this issue as an 'other matter' was provided prior to the release of the AER's likely approach to the classification of its distribution services. The AER notes that it classified Energex's and Ergon's street lighting services as an alternative control service.

The NER states that the RAB should include only the value of assets that provide standard control services and only to the extent that they are used to provide such services (clause 6.5.(1)). Therefore, the RAB for the next regulatory control period should not include street lighting assets (alternative control services). [123]

In the context of rolling forward street lighting assets, the NER sets out Ergon's opening regulatory asset base (RAB) as at 1 July 2005 and matters relevant to the establishment of a DNSP's regulatory asset base (schedule 6.2 and clause 6.5.1). The AER is required to asses Ergon's proposed RAB in accordance with the NER and subject to the distribution consultation procedures.

The reasonableness of the approach undertaken by Ergon to roll forward its street lighting assets will be reviewed in accordance with the NER at the time of assessing its regulatory proposal. Street lighting services continue as a standard control service (prescribed service under the QCA 2005 distribution determination) until the end of the current regulatory period (30 June 2010) and will remain in the RAB until then.

AER decision

In relation to the RFM and PTRM, the AER considers it unnecessary to indicate its likely approach on the treatment of street lighting assets in its framework and approach paper.

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[123] The AER recognises that transitional provisions in the NER applicable to the Queensland DNSPs may allow for some differences in approach than what is provided for by schedule 6.2 and clause 6.5.1.

5.2.4 Regulatory asset base value

Submissions

Ergon stated that clause S6.2.1(c)(1) of the NER sets the value of its opening RAB as at 1 July 2005 at $4198.2 million (July 2005 dollars) and that the clause permits the QCA (as the relevant jurisdictional regulator) to nominate in writing to the AER a value which differs from the amount set out in the NER.

Ergon submitted that it had previously written to the AER advising that its opening RAB value as at 1 July 2005 should actually be $4232.4 million. It noted that it had enclosed a letter dated 23 March 2006 from the QCA to Ergon which discussed the revised RAB value. The QCA letter noted that Ergon's opening asset base was adjusted by the QCA to reflect actual capex outcomes in the final year of the previous regulatory period. Ergon had sought confirmation from the AER that the copy of the QCA letter was sufficient to satisfy clause S6.2.1(c)(1) of the NER.

Ergon requested that the AER confirm that it agrees to replace the $4198.2 million (July 2005 dollars) value with the $4232.4 million value.

Additionally, Ergon stated that it intends to reduce its opening RAB value (1 July 2005) by a further $39 million resulting in a final value of $4193.9 million. It stated that this amount was included by the QCA as inventory but as the PTRM adopted by the AER has working capital allowances inventory is no longer required.[124]

AER consideration

The NER permits the QCA to nominate an amount different to that set out in clause S6.2.1(c)(1). In response to a written request from the AER, the QCA confirmed that it had revised Ergon's opening RAB to $4232.4 million (July 2005 dollars). The correspondence on this matter is set out in Appendix A. In relation to Ergon's proposal to reduce $39 million on account of inventory, the AER notes that any adjustments to the 2005 opening RAB should be done consistent with the relevant NER clauses. Any such RAB adjustments should be included in Ergon's regulatory proposal. The validity of any adjustment proposed by Ergon will be reviewed in accordance with the NER by the AER when assessing Ergon's regulatory proposal.

AER decision

The AER will adopt the 1 July 2005 opening RAB value of $4232.4 million (July 2005 dollars) nominated by the QCA.

The AER will review and consult upon Ergon's proposal to reduce its opening RAB as at 1 July 2005 by $39 million (as a result of the removal of the inventory asset category) as part of its review of Ergon's regulatory proposal and not as part of the framework and approach process.

[124] Ergon, op. cit., pp. 13–14.

5.2.5 No prudency review

Submissions

Ergon submitted that the NER does not provide for the AER to undertake a prudency review of its capital expenditure during the current 2005–10 regulatory period. It requested that the AER confirm that Ergon will be allowed to roll forward the actual capex incurred by it consistent with the roll forward model by applying chapters 6 and 11 of the NER.[125]

AER consideration

Generally, a prudency review will examine each stage of the decision making process when selecting and delivering investments and retrospectively judge whether decisions have been undertaken prudently. 'Prudency' is generally viewed to be consistent with sound judgement, avoidance of undesired consequences, managing carefully and economically.

For the DNSPs whose opening RAB has been set out in clause S6.2.1(c), in the first round of distribution determinations under the revised NER, there is no provision in the NER for the AER to adjust past capex on account of prudency considerations for the purpose of rolling forward the RAB. Ergon's opening RAB as at 1 July 2005 has been set out in clause S6.2.1(c) (modified according to section 5.2.4 above).

Actual and expected capex and operating expenditure (opex) during any preceding regulatory control period are relevant factors that it must have regard to when assessing Ergon's forecast capex and opex.[126] Therefore, the AER is required to undertake a review of past capex and opex to the extent that such a review will inform the assessment of Ergon's forecast capex and opex proposal. For example, if there is likely to be a capex overspend in the current regulatory period the AER will review the past capex to understand the reasons for that overspend and how they might impact on forecast capex.

AER decision

The NER do not permit the AER to undertake a prudency review of Ergon's capex for the current regulatory period. Ergon is permitted to roll forward the actual capex incurred by it consistent with the RFM as provided for in the NER. However, consistent with the NER, the AER will undertake a review of past capex and opex to inform its decision on the forecast capex and opex to apply in the next regulatory control period.

5.2.6 Cost pass through for input cost increases

Submissions

Energex and Ergon stated that clause S6.1.3 of the NER requires them to include in their building block proposal a pass through clause with a proposal as to the events that should be defined as pass through events. The DNSPs further noted that under clause 6.12.1(14) the AER must include in its distribution determination a decision on the additional pass through events that are to apply for the regulatory control period.

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125 Ergon, op. cit., p.14.
126 NER, clause 6.5.7(e)(5) and 6.5.7(e)(5).

Energex and Ergon also referred to comments made by the AER in its *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, that there "…may be scope to nominate significant input cost variations as pass through events".[127] Further, Ergon noted that Energy Australia, Country Energy and ActewAGL have relied on the AER's above statement in relation to nominating pass through events in their 2008 regulatory proposals.

Energex and Ergon sought confirmation from the AER that they are allowed to nominate significant input cost variations as pass through events in their regulatory proposal.[128, 129]

AER consideration

The AER is currently reviewing the ACT and NSW DNSP's nominated cost pass through events included in their regulatory proposals. The nominated events include input costs increases. While the distribution determinations for those DNSP's will provide guidance for Energex and Ergon in making their regulatory proposals, each DNSP's proposal will be considered on its own merits.

A constituent part of the distribution determination is a decision on the additional (nominated) pass through events that are to apply for the regulatory control period.[130] A DNSP has discretion on what it nominates as pass through events in its regulatory proposal. Energex's and Ergon's regulatory proposals will be reviewed in consultation with interested parties.

AER decision

The AER considers that an indication of its likely approach is inappropriate given that it is required to make its decision on nominated events at the time of making its distribution determination after assessing the regulatory proposal and submissions from interested parties.

5.2.7 Cost pass through materiality threshold

Submissions

Energex and Ergon stated that the AER has not released a guideline in relation to its likely approach for the Queensland DNSP's pass through events and noted that such a guideline is permitted under clause 6.2.8(a)(4) of the NER. They also noted that the AER's preliminary positions paper on *Matters relevant to distribution determinations for the ACT and NSW DNSPs for 2009–14* foreshadowed the following two materiality thresholds for cost pass throughs events:

- revenue impact from the event in any one year is more than 1 per cent of the revenue for the first year of the regulatory control period

- the capex associated with the event exceeds 5 per cent of the annual revenue requirement ARR in the first year of the regulatory period.

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127 AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, Final decision, February 2008, pp. 11–12.
128 Energex, op. cit., p. 19.
129 Ergon, op. cit., p. 16.
130 NER, clause 6.12.4(14).

Energex and Ergon sought confirmation that the AER will apply the same two materiality thresholds foreshadowed for the ACT and NSW distribution businesses to the Queensland DNSPs. Additionally Ergon requested that the AER agree that these be incorporated into a guideline.[131, 132]

AER consideration

The publishing of a guideline on this matter by the AER is discretionary. The AER is not required to consider the materiality of events when it makes its distribution determinations for the Queensland DNSPs. By including events in its distribution determination the AER is not making an assessment of materiality. The materiality of an event is only considered when a pass through application is made. While guidance on the materiality threshold will be useful to a DNSP in deciding whether or not to make a pass through application, it is not an essential component of the regulatory proposal.

AER decision

The AER considers that an indication of its likely approach on cost pass through materiality threshold is not necessary in the framework and approach paper.

5.2.8 Cost pass through for alternative control services

Submissions

Energex and Ergon stated that it is not clear whether the NER allows cost pass through events in relation to alternative control services or whether the NER provisions apply only to standard control services. The DNSP's sought confirmation from the AER that they are entitled to apply the cost pass through provisions contained in clause 6.6.1 to alternative control services and would also be allowed to nominate events that apply to these services.[133, 134]

AER consideration

A pass through application can only be made in relation to pass through events identified in the NER or determined by the AER as additional pass through events in its distribution determination. Therefore, an indication on whether pass through events in relation to alternative control services are allowed to be nominated under the NER will enable the DNSPs to propose a regulatory proposal consistent with the AER's likely approach. If Energex and/or Ergon nominates pass through events that apply to alternative control services then the AER will make a decision on these events at the time of making the distribution determination based on the merits of each proposal and consultation with interested parties.

AER decision

The NER permits nominated pass through events in relation to alternative control services and these need to be addressed as part of the regulatory proposal.

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131 Energex, op. cit., p. 18.
132 Ergon, op. cit., p. 17.
133 Energex, op. cit., p.19.
134 Ergon, op. cit., p. 18.

5.2.9 Eligible pass through amount, information requirements and processes

Submissions

Ergon submitted that in addition to understanding the materiality threshold, the DNSPs need:

- clarity as to what is included in the eligible pass through amounts which is defined in the NEL as – in respect of a positive change event for a DNSP, the increase in costs in the provision of direct control services that the DNSP has incurred and is likely to incur until the end of the regulatory control period as a result of that positive change event (as opposed to the revenue impact of the event)
- to know the AER's information requirements when assessing cost pass through applications
- details on how the AER will apply the processes set out in clause 6.6.1 in relation to cost pass through.

Therefore, Ergon requested that the AER confirm that it intends preparing a guideline addressing the above issues.[135]

AER consideration

The clarifications sought by Ergon relate to matters directly associated with pass through applications which relate to adjusting the building block determination after the distribution determination has been made. As noted above the framework and approach paper is a document targeted at providing information to the DNSPs on the AER's likely approach to certain matters so that they are able to prepare their regulatory proposals. The issues raised by Ergon do not relate to the preparation of its regulatory proposal.

AER decision

The AER considers that an indication of its likely approach on these matters at this stage of the process is unnecessary as it relates to the making of a decision after the distribution determination has been made.

5.2.10 Security of supply standards

Submissions

Both Energex and Ergon submitted that there was no codified security of supply requirements in Queensland.[136, 137] The DNSPs noted that the opex and capex objectives in the NER required them to develop opex and capex forecasts to maintain security of supply.[138] Hence, Energex and Ergon requested that the AER agree to them developing their opex and capex forecasts based on maintaining the security of

135 Ergon, op. cit., p. 17.
136 Energex, op. cit., p. 18.
137 Ergon, op. cit., pp. 19–20.
138 NER, clause 6.5.6(a)(3), 6.5.6(a)(4), 6.5.7(a)(3) and 6.5.7(a)(4).

supply standards approved by the Queensland Government for the purposes of delivering against the:

- Electricity Distribution and Service Delivery (EDSD) review recommendations
- the associated Queensland Government action plan.[139, 140]

AER consideration

The NER sets out the forecast opex and capex objectives. Inter alia, the relevant provisions state that the expenditure should be required to achieve compliance with all applicable regulatory obligations or requirements and maintain the quality, reliability and security of supply of providing the distribution service.[141] The AER is required to make its decision on the DNSP's opex and capex proposals in line with the criteria in the NER which include an assessment of whether the proposed expenditure reasonably reflects the efficient cost of achieving the opex and capex objectives.

The AER has written to the Queensland Department of Mines and Energy (DME) requesting that they confirm that the EDSD recommendations are the applicable security of supply standards and whether the DNSPs have achieved these standards or if not, when they are likely to do so.

In the event that the standards are revised prior to the regulatory proposal due date (31 May 2009), the AER will be guided by the DME's position on the revised standards required of the DNSPs.

AER decision

The AER will be guided by the DME's position on the security of supply standards applicable to the DNSPs for the next regulatory control period.

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[139] Energex, op. cit., p. 18.
[140] Ergon, op. cit., pp. 19–20
[141] NER, clause 6.5.6(a) and 6.5.7(a).

Appendix A: Regulatory asset base value

Section 5.2.4 set out the AER's consideration of the value of Ergon's opening asset base as at 1 July 2005. The correspondence referred to in that section is attached below.

QUEENSLAND COMPETITION AUTHORITY

Our Ref: Gary Henry
Direct Line: 07 3222 0504
File Ref: 230207

D08 | 102 382

6 October 2008

Mr Mike Buckley
General Manager
Network Regulation North Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Dear Mr Buckley

I refer to your letter of 24 September 2008 seeking the Queensland Competition Authority's (the Authority's) advice on Ergon Energy's regulatory asset base value at 1 July 2005.

Ergon Energy's opening asset base value was revised to $4,232.4 million in nominal dollars at 1 July 2005. The adjustment was made to reflect actual capex data for 2004-05 that became available after the Authority completed its 2005 Final Determination. This amendment was provided for in the Authority's Final Determination.

Yours sincerely

EJ Hall
Chief Executive

AUSTRALIAN ENERGY
REGULATOR

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Our Ref: C2008/1047

Contact Officer: Scott Haig
Contact Phone: 02 6243 1093

24 September 2008

Mr Gary Henry
Director, Energy
Queensland Competition Authority
GPO Box 2257
BRISBANE, QLD, 4001

Dear ~~Mr Henry~~ Gary

Ergon Energy's regulatory asset base as at 1 July 2005

I am writing to you regarding the opening regulatory asset base (RAB) value for Ergon Energy as at 1 July 2005. As part of its upcoming distribution determination for Ergon Energy the AER is required to roll forward Ergon Energy's opening RAB value.

Clause S6.2.1(c)(1) of the National Electricity Rules (NER) sets the value of Ergon Energy's RAB as at 1 July 2005 at $4198.2 million (July 2005 dollars). This clause also permits the Queensland Competition Authority (QCA) to nominate in writing to the AER a value which differs from the amount set out in the NER.

On 8 July 2008 Ergon Energy wrote to the AER advising that its opening RAB value as at 1 July 2005 should be $4,232.4 million. In support of this revised RAB value, Ergon Energy enclosed a letter dated 23 March 2006 from the QCA to Ergon Energy which discusses the revised RAB value. Ergon Energy has sought confirmation from the AER that the copy of the QCA letter was sufficient to satisfy clause S6.2.1(c)(1) of the NER. It is understood that the revised RAB value stated in the 2006 QCA letter was primarily due to an adjustment to reflect actual capex outcomes in the final year of the previous regulatory period.

In accordance with clause S6.2.1(c)(1) of the NER, could you please advise whether the QCA nominates the amount of $4232.4 million referred to in its letter dated 23 March 2006 as Ergon Energy's RAB as at 1 July 2005 and whether that amount is in July 2005 dollars.

Should you wish to discuss please contact Scott Haig on (02) 6243 1207 or Pradeep Fernando on (02) 6243 1264.

Yours sincerely

Mike Buckley
General Manager
Network Regulation North Branch

Copy: Mr Tony Pfeiffer, General Manager – Regulatory Affairs, Ergon Energy