Draft decision – Appendices

Queensland

Draft distribution determination 2010–11 to 2014–15

25 November 2009

AUSTRALIAN ENERGY REGULATOR

A. Distribution service classification

Table A.1: Ergon Energy service classifications

AER service group	AER classification	Activities included in service group	Ergon Energy service
Network services	Standard control service	Constructing the network	DNSP funded construction of distribution network assets
		Maintaining the network	Network maintenance
		Operating the network for DNSP purposes	Network operations
		Planning the network	Network planning (load on system, future requirements for system)
		Designing the network	Design standards and designing the network
		Emergency response	Emergency response emergency services (for example, reinstatement of network after natural disaster)
		Administrative support	Call centres Network claim processing Network billing Supply of electricity to a customer’s electrical installation or premises Network switching and testing for DNSP purposes

AER service group	AER classification	Activities included in service group	Ergon Energy service
Network services (cont)	Standard control service	Administrative support	Populate and maintain National Metering Identifier (NMI) standing data in Market Settlement and Transfer Solution
			NMI discovery request
			Cold water reports
			Loss of supply (DNSP fault)
			Creation and allocation of NMI
Connection services	Standard control service	Commissioning of connection assets	Provision of connection services (for example, connection asset such as padmount transformer, service line for metered and unmetered connections)
		Service connections for small customers	
		Installation inspection	Inspection and testing of electrical work
		Operating and maintaining connection assets	Operating and maintaining connection assets
Metering services	Standard control service	Commissioning of metering and load control equipment	Provision and installation of hot water meter and load control equipment
		Type 5 – 7 metering	Provision and installation of type 5 – 7 meter
			Provision of minimum requirement of historical (2 years) type 5 – 7 metering data
		Scheduled meter reading	Scheduled meter read

AER service group	AER classification	Activities included in service group	Ergon Energy service
Metering services (cont)	Standard control service	Unscheduled meter reading – non-chargeable	Final meter read
		Metering investigation	Meter tampering (where an onsite inspection is required to determine if equipment tampering has occurred)
			Meter inspection (where onsite inspection is required to determine if fault has occurred)
		Maintaining and repairing meters and load control equipment	
Street lighting services	Alternative control service	Provision, construction and maintenance of street lighting	Street Lighting - Provision and Operating and Maintenance
Quoted services	Alternative control service	Rearrangement of network assets	Removal/relocation of Ergon Energy's assets at customer request
			Move point of attachment at customer request
		Covering of low voltage mains	Tiger tails
		Non standard data services (type 5 – 7 metering)	Metering Data Provider services
			Metering Data Provider services above minimum requirements (reading and data)
		Ancillary metering services (type 5 – 7)	type 5 – 7 meter test
			Change tariff
			Change time switch
			Removal of meter type 5 – 7

AER service group	AER classification	Activities included in service group	Ergon Energy service
Quoted services (cont)	Alternative control service	Ancillary metering services (type 5 – 7)	Removal of load control device
			Special meter read (off-cycle meter read during business hours)
			Reprogram card meters
			Exchange meter
			Move meter
		Supply enhancement	Provision of connection services above minimum requirements
			Overhead service upgrade
			Underground service upgrade
		Metering enhancement	Provision, installation and maintenance of meters above minimum requirements
			Prepayment meters at customer request
		Temporary disconnect/reconnect services	Temporary disconnection and reconnection (including de-energisations and re-energisations involving a line drop; for example, connecting building sites/community events)
		After hours provision of any service	De-energisation after hours
			Re-energisation after hours
			Attend loss of supply after hours
		Emergency recoverable works	Emergency recoverable works (for example, repair of shared network due to vehicle accident)
		Large customer connections	Provision of connection services (for example, connection asset such as padmount transformer, service line for metered and unmetered connections)

AER service group	AER classification	Activities included in service group	Ergon Energy service
Quoted services (cont)	Alternative control service	Auditing of design and construction	Subdivision fees Project fees
		Miscellaneous	High load escorts - lifting of lines Rectification of illegal connections Conversion of aerial bundled cables Provision of service crew / additional crew
Fee based services	Alternative control service	Specification and design enquiry fees	Subdivision fees Project fees
		De-energisation and re-energisation	De-energisation during business hours - urban/short rural feeders De-energisation during business hours - long rural/isolated feeders Re-energisation during business hours - urban/short rural feeders Re-energisation during business hours - long rural/isolated feeders
		Re-test	Re-test a customer's installation during business hours - urban/short rural feeders
		Re-test	Re-test at customer's installation during business hours - long rural/isolated feeders
		Supply abolishment	Supply abolishment during business hours - urban/short rural feeders Supply abolishment during business hours - long rural/isolated feeders

AER service group	AER classification	Activities included in service group	Ergon Energy service
Fee based services	Alternative control service	Temporary supply service	Temporary builders supply, not in permanent position - single phase metered - business hours - urban/short rural feeders
			Temporary builders supply, not in permanent position - single phase metered - business hours - long rural/isolated rural feeders
			Temporary builders supply, not in permanent position - multi phase metered - business hours - urban/short rural feeders
			Temporary builders supply, not in permanent position - multi phase metered - business hours - long rural/isolated feeders
		Fault response – not DNSP fault	Restoration of supply due to customer action, during business hours - urban/short rural feeders
			Restoration of supply due to customer action, during business hours - long rural/isolated feeders
		Wasted attendance	Wasted truck visit - one person crew - urban/short rural feeders
			Wasted truck visit - one person crew - long rural/isolated feeders
			Wasted truck visit - two person crew - urban/short rural feeders
			Wasted truck visit - two person crew - long rural/isolated feeders

Table A.2: Energex service classifications

AER service group	AER classification	Activities included in service group	Energex service[1167]
Network services	Standard control service	Constructing the network	Constructing the network
		Maintaining the network	Maintaining the network
		Operating the network for DNSP purposes	Operating the network for DNSP purposes
		Planning the network	Planning the network
		Designing the network	Designing the network
		Emergency response	Emergency response
		Administrative support	Administrative support
Connection services	Standard control service	Commissioning of connection assets	Commissioning of connection assets
		Service connections for small customers	Service connections for small customers
		Installation inspection	Installation inspection
		Operating and maintaining connection assets	Operating and maintaining connection assets

1167 Energex has advised that its services provided under the AER's service groups classified as standard control services and the alternative control street lighting service are more appropriately described by the activity descriptor rather than as specific services. Some activities have been identified under both quoted and fee based services.

AER service group	AER classification	Activities included in service group	Energex service
Metering services	Standard control service	Commissioning of metering and load control equipment	Commissioning of metering and load control equipment
		Type 5-7 metering	Type 5-7 metering
		Scheduled meter reading – non-chargeable	Scheduled meter reading – non-chargeable
		Metering investigation	Metering investigation
		Maintaining and repairing meters and load control equipment	Maintaining and repairing meters and load control equipment
Street lighting services	Alternative control service	Provision, construction and maintenance of street lighting	Provision, construction and maintenance of street lighting
Quoted services	Alternative control service	Rearrangement of network assets	Rearrangement of network assets
			Loss of asset
		Covering of low voltage mains	Customer requested works to allow customer or contractor to work close[1168]
		Non standard data services (type 5-7 metering)	Non standard data services and metering services (type 5-7 metering)
		Ancillary metering services (type 5-7)	
		Supply enhancement	Unmetered services, including street lighting

[1168] This service could also be a service within disconnect/reconnect activity.

AER service group	AER classification	Activities included in service group	Energex service
Quoted services (cont)	Alternative control service	Supply enhancement	Additional crew
			Other recoverable works
		Supply abolishment	Supply abolishment – complex
		Metering enhancement	Other recoverable works
		Temporary supply service	Temporary connection - complex
		After hours provision of any service	After hours provision of any fee-based service (excluding re-energisations)
			Attending loss of supply – LV customer installation at fault
		Emergency recoverable works	Emergency recoverable works and rectification of illegal connections
		Large customer connections	Large customer connections
		Auditing of design and construction	Design specification/auditing and other subdivision activities
Fee based services	Alternative control service	Specification and design enquiry fees	
		De-energisation and re-energisation	De-energisation
			Re-energisation – after hours (AH)
			Re-energisation – business hours (BH)
			Re-energisation (Visual) - BH
			Re-energisation (Visual) - AH

AER service group	AER classification	Activities included in service group	Energex service
Fee based services (cont)	Alternative control service	De-energisation and re-energisation	Re-energisation non-payment (Visual) BH Re-energisation non-payment (Visual) AH
		Re-test	
		Supply abolishment	Supply abolishment - simple
		Temporary supply service	Temporary connection - simple Unmetered supply
		Fault response – not DNSP fault	Attending loss of supply – Low voltage customer's installation at fault (BH)
		Wasted attendance	Site visit

B. Assigning customers to tariff classes

Procedures for assigning or reassigning customers to tariff classes

Assignment of existing customers to tariff classes at the commencement of the next regulatory control period

1. Each customer who was a customer of a Qld DNSP prior to 1 July 2010, and who continues to be a customer of a Qld DNSP as at 1 July 2010, will be taken to be "assigned" to the tariff class which the Qld DNSP was charging that customer immediately prior to 1 July 2010.

Assignment of new customers to a tariff class during the next regulatory control period

2. If, after 1 July 2010, a Qld DNSP becomes aware that a person will become a customer of the DNSP, then the DNSP must determine the tariff class to which the new customer will be assigned.

3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with section 2 or 5, a DNSP must take into account one or more of the following factors:

   (a) the nature and extent of the customer's usage

   (b) the nature of the customer's connection to the network[1169]

   (c) whether remotely read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

4. In addition to the requirements under section 3, a Qld DNSP, when assigning or reassigning a customer to a tariff class, must ensure the following:

   (a) that customers with similar connection and usage profiles are treated equally

   (b) that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

Reassignment of existing customers to another existing or a new tariff during the next regulatory control period

5. If a Qld DNSP believes that an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or

[1169] The AER interprets 'connection' to include the installation of any technology capable of supporting time based tariffs.

materially similar load or connection characteristics as other customers on the customer’s existing tariff, then it may reassign that customer to another tariff class.

Objections to proposed assignments and reassignments

6. A Qld DNSP must notify the customer concerned in writing of the tariff class to which the customer has been assigned or reassigned by it, prior to the assignment or reassignment occurring. If the DNSP does not know the identity of the customer then it must notify the customer’s retailer instead.

7. The notice under section 6 must include advice that the customer may request further information from the DNSP and that it may object to the proposed assignment or reassignment. This notice must specifically include:

    a. either a copy of the DNSP’s internal procedures for reviewing objections or the link to where such information is available on the DNSP’s website

    b. that if the objection is not resolved to the satisfaction of the customer under the DNSP’s internal review system, then to the extent that resolution of such disputes are within the jurisdiction of a state based energy ombudsman scheme the customer is entitled to escalate the matter to such a body

    c. that if the objection is not resolved to the satisfaction of the customer under the DNSP’s internal review system, then the customer is entitled to seek resolution via the dispute resolution process available under Part 10 of the NEL.

8. If, in response to a notice issued in accordance with section 6, a Qld DNSP receives a request for further information from a customer, then it must provide such information. If any of the information requested by the customer is confidential then it is not required to provide that information to the customer.

9. If, in response to a notice issued in accordance with section 7, a customer makes an objection to a Qld DNSP about the proposed assignment or reassignment, the relevant Qld DNSP must reconsider the proposed assignment or reassignment, taking into consideration the factors in sections 3 and 4 above, and notify the customer in writing of its decision and the reasons for that decision.

10. If a customer’s objection to a tariff assignment or reassignment is upheld by the relevant external dispute resolution body, then any adjustment which needs to be made to prices will be done by the Qld DNSP as part of the next annual review of prices.

System of assessment and review of the basis on which a customer is charged

11. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer’s usage or load profile, the Qld DNSP must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.

12. If the AER considers that the method provided under section 11 does not provide for an effective system of assessment and review of the basis on which a customer is charged, the AER may request additional information or request that the relevant Qld DNSP revise and resubmit a revised method.

13. If the AER considers the method provided in accordance with section 11 is reasonable it will approve that method by notice in writing to the Qld DNSP.

C. Negotiated distribution service criteria

National Electricity Objective

1. The terms and conditions of access for a negotiated distribution service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

Criteria for terms and conditions of access

Terms and Conditions of Access

2. The terms and conditions of access for a negotiated distribution service must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for a negotiated distribution service (including in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between a distribution network service provider (DNSP) and any other party, the price for the negotiated distribution service and the costs to a DNSP of providing the negotiated distribution service.
4. The terms and conditions of access for a negotiated distribution service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of Services

5. The price for a negotiated distribution service must reflect the costs that a DNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the DNSP’s Cost Allocation Method.
6. Subject to criteria 7 and 8, the price for a negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand alone basis.
7. If a negotiated distribution service is a shared distribution service that:
    i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation: or
    ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER,

    then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect a DNSP’s incremental cost of providing that service.
8. If a negotiated distribution service is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared

distribution service which meets, but does not exceed, the network performance requirements, should reflect the cost a DNSP would avoid by not providing that service.

9. The price for a negotiated distribution service must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.

10. The price for a negotiated distribution service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

11. The price for a negotiated distribution service must be such as to enable a DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated distribution service.

Criteria for access charges

Access Charges

12. Any charges must be based on costs reasonably incurred by a DNSP in providing distribution network user access, and, in the case of compensation referred to in clauses 5.5(f)(4)(ii) and (iii) of the NER, on the revenue that is likely to be forgone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs.

13. Any charges must be based on costs reasonably incurred by a DNSP in providing transmission network user access to services deemed to be negotiated distribution services by clause 6.24.2(c) of the NER, and, in the case of compensation referred to in clauses 5.4A(h) to (j) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs.

D. Distribution use of system unders and overs account

To demonstrate compliance with their distribution determinations the next regulatory control period, the AER requires the Qld DNSPs to maintain a distribution use of system (DUOS) unders and overs account. The Qld DNSPs must provide information on this account to the AER as part of their annual pricing proposals under clause 6.18.2(b)(7) of the NER.

The Qld DNSPs must provide the amounts for the following entries in their DUOS unders and overs account for the most recently completed regulatory year (t–2) and the next regulatory year (t):

1. opening balance for year t–2 and year t.
2. an interest charge for two years on the opening balance in year t–2. This adjustment should be calculated using the approved nominal weighted average cost of capital (WACC). No such charge applies to the opening balance for year t.
3. the amount of revenue recovered from DUOS charges in respect of that year, less the allowed maximum allowed revenue (MAR) for the year in question.
4. an interest charge for two years related to the net amount in item 3 for year t–2. This adjustment should be calculated using the approved nominal WACC. No such charge applies to the net amount in item 2 for year t.
5. the total of items 1–4 to derive the closing balance for each year.

The Qld DNSPs must provide details of calculations in the format set out in table D.1. Amounts provided for the most recently completed regulatory year (t–2) must be audited. Amounts for the next regulatory year (t) will be regarded as a forecast.

In proposing variations to the amount and structure of DUOS charges, the Qld DNSPs are to achieve an expected zero balance on their DUOS unders and overs accounts at the end of each regulatory year in the next regulatory control period, unless the DNSP can demonstrate for a given year that such an adjustment exceeds the agreed tolerance limits set out in chapter 4 of this draft decision. In such circumstances, the balance at the end of the regulatory control period will reflect the amount by which the adjustment would exceed the first tolerance limit (that is, the amount by which the under/over adjustment would exceed 2 per cent of the DNSP's revenues).

The proposed prices for year t will be based on the sum of the MAR for year t plus any under/over recovery for year t, up to 2 per cent of the DNSP's revenues unless otherwise agreed between the AER and the DNSP.

Table D.1: Example calculation of DUOS unders and overs account ($'000)

	year t–2 (actual)	year t (forecast)
Revenue from DUOS charges	36 221	45 761
MAR for the relevant year [a]	34 365	46 694
Under/over recovery for regulatory year	1856	–933
DUOS unders and overs account		
Nominal WACC	9.70%	na
Opening balance	1000[b]	3437
Interest on opening balance	203	na
Under/over recovery for regulatory year	1856	–933
Interest on under/over recovery for regulatory year	378	na
Closing balance	3437[c]	2504

(a) The formula used to determine the MAR for each year is set out in chapter 4 of this draft decision.

(b) The opening balance for year t–2 is based on any DUOS under/over recoveries prior to year t–2 that were in excess of the agreed tolerance limits and have therefore not yet been returned to (recovered from) customers yet.

(c) In this example, the under/over adjustment required to achieve zero balance ($3437 000) on the DUOS unders and overs account would exceed the first tolerance limit. Therefore the adjustment has been capped at 2 per cent ($933 000) of MAR for year t.

E. Transmission use of system unders and overs account

To demonstrate compliance with clause 6.18.7 of the NER and their distribution determinations in the next regulatory control period, the AER requires the Qld DNSPs to maintain a transmission use of system (TUOS) unders and overs account. The Qld DNSPs must provide information on this account to the AER as part of their annual pricing proposals under clause 6.18.2(b)(7) of the NER.

The Qld DNSPs must provide the amounts for the following entries in their TUOS unders and overs account for the most recently completed regulatory year (t–2) and the next regulatory year (t):

1. the opening balance for each year. The opening balance for year t–2 should be zero.

2. the amount of revenue recovered from TUOS charges applied in respect of that year, less the amounts of all transmission related payments made by the DNSP in respect of that year.

3. an interest charge for two years related to the net amount in item 2 for year t–2. This adjustment should be calculated using the approved nominal weighted average cost of capital (WACC). No such adjustment applies to the net amount in item 2 for year t as no such adjustment was required by the QCA.

4. the total of items 1–3 to derive the closing balance for each year.

The Qld DNSPs must provide details of calculations in the format set out in table E.1 of this draft decision. Amounts provided for the most recently completed regulatory year (t–2) must be audited. Amounts for the next regulatory year (t) will be regarded as forecasts.

In proposing variations to the amount and structure of TUOS charges for a given regulatory year t, the Qld DNSPs are to achieve a zero expected balance on their TUOS unders and overs account at the end of each regulatory year in the regulatory control period.

Table E.1: Example calculation of TUOS unders and overs account ($'000)

	year t–2 (actual)	year t (forecast)
Revenue from TUOS charges	36 221	36 500
Transmission charges to be paid to TNSPs	25 214	29 557
Avoided TUOS payments	572	681
Inter-DNSP payments	8579	8496
Total transmission related payments	34 365	38 734
Under/over recovery for regulatory year	1856	–2036
TUOS unders and overs account		
Nominal WACC	9.70%	na
Opening balance	0	2234
Under/over recovery for financial year	1856	–2234
Interest on under/over recovery for regulatory year	378	na
Closing balance	2234	0

F. Energex forecast capex

F.1 Introduction

This appendix sets out the AER's detailed considerations and conclusions on Energex's proposed capex allowance for the next regulatory control period. The regulatory requirements and the general approach used by the AER to assess Energex's capex proposal is set out in chapter 7. This appendix includes:

- an overview of Energex's capex proposal
- specific comments on the capex proposal from stakeholders
- the review and findings of the AER's consultant, PB
- the issues and the AER's reasoning and considerations, including a discussion of proposed capex by category
- the AER's conclusions on the forecast capex allowance for Energex.

F.2 Energex regulatory proposal

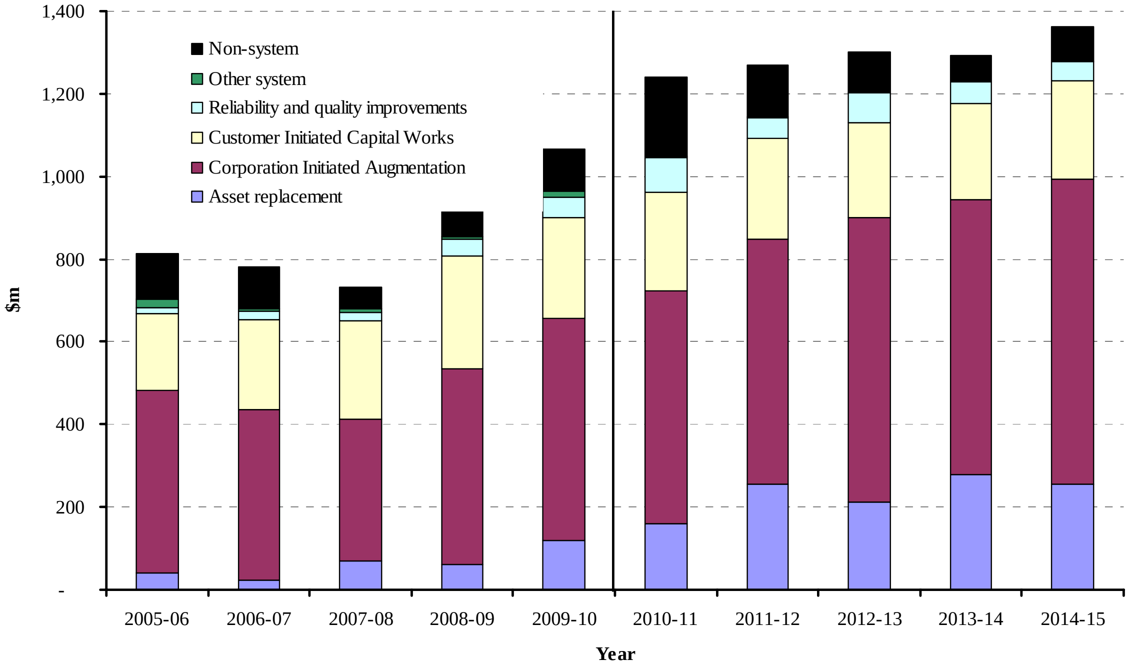
Energex proposed a capex allowance totalling $6466 million ($2009–10) for the next regulatory control period. Table F.1 shows the annual profile of Energex's capex proposal by category. Figure F.1 compares Energex's forecast capex with actual expenditure incurred in the current regulatory control period.

Table F.1: Energex's capex proposal by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Growth	416.7	457.0	533.0	569.3	637.2	2613.2
Asset replacement/renewal	160.5	255.7	212.9	280.2	256.0	1165.3
Reliability and quality of service enhancement	85.8	50.6	72.6	51.6	45.7	306.3
Security compliance	384.0	381.6	385.0	328.1	338.6	1817.3
Total system capex	1047.1	1144.9	1203.6	1229.2	1277.5	5902.3
Non-system capex	192.3	124.8	98.4	63.2	85.0	563.7
Total capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0

Source: Energex, *Regulatory proposal*, July 2009, p. 193.
Note: Totals may not add due to rounding.

Figure F.1: Energex's actual and proposed capex by driver ($m, 2009–10)



Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

Energex's forecast capex for the next regulatory control period is approximately 50 per cent higher than the level expected during the current regulatory control period. Energex noted that capex in the categories of growth, security compliance, replacement and refurbishment of assets, and reliability account for 90 per cent of total forecast capex.[1170]

Energex has proposed growth capex of $2613 million ($2009–10), which accounts for 40 per cent of total forecast capex and represents an increase of 29 per cent compared to the current regulatory control period. Around 55 per cent of growth capex is augmentation expenditure, including assets such as bulk supply and zone substations, and overhead and underground cables. The remaining 45 per cent of growth capex is for connecting residential and other customers excluding larger commercial and industrial customers. (The design and construction of connection assets for larger customers is an alternative control service and is not included in forecast capex).[1171]

Energex forecast security compliance capex of $1817 million ($2009–10), which accounts for 28 per cent of Energex's total forecast capex program and represents an increase of 29 per cent compared to the current regulatory control period. Energex stated this capex category is based on projects to augment the network and reduce loading on lines and substations to a level such that failure of one component does not result in a sustained outage to customers.[1172]

[1170] Energex, *Regulatory proposal*, July 2009, p. 193.
[1171] Energex, *Regulatory proposal*, July 2009, p. 202.
[1172] Energex, *Regulatory proposal*, July 2009, pp. 202–203.

Energex proposed $1165 million ($2009–10) in renewal and replacement capex, which is a 271 per cent (in real terms) increase on expenditure in the current regulatory control period. Energex stated that it has a significant number of aged assets that require refurbishment or replacement. Energex's major asset renewal and replacement projects and programs are:[1173]

- works provisions relating to maintenance of supporting structures for powerlines that require a pole failure rate of less than one in 10 000 per annum ($234 million)
- programs targeting equipment on the distribution network including 11kV ring main units, air break switches, pole mounted plant and replacement of timber cross-arms with wide trident steel supports ($292 million)
- refurbishment of identified 11kV feeders ($131 million)
- replacement and refurbishment of sub-transmission 33kV and 110kV lines ($161 million)
- bulk supply and zone substation plant, including transformers, switchgear and ancillary equipment ($159 million)
- refurbishment and replacement of obsolete and aging telecommunications and SCADA equipment ($135 million).

Energex proposed $306 million ($2009–10) of reliability and quality of service capex. This is approximately 114 per cent (in real terms) higher than that of the current regulatory control period. Energex stated the driver for this increase is to improve reliability by installing fault isolating devices in the network, building small rural substations and rebuilding rural overhead lines.[1174]

Energex's proposed non–system capex of $564 million ($2009–10) includes expenditure on end–use computing assets, motor vehicles, land and buildings, and tools and equipment. Non–system capex represents approximately 9 per cent of the total forecast capex program. This expenditure is driven by a range of programs and projects to replace aged equipment and facilities, address the extensive use of temporary accommodation, and manage and mitigate safety and health risks in the workplace. Examples of these projects include:[1175]

- replacement of three major amenities including logistics and warehousing, training and pole depot facilities
- construction of five new regional administration centres to reduce pressure on current regional field response facilities
- acquisition of land and construction of seven unmanned sites for secure storage of critical spare parts and heavy machinery in close proximity to customers

[1173] Energex, *Regulatory proposal*, July 2009, pp. 203–204.
[1174] Energex, *Regulatory proposal*, July 2009, pp. 204–205.
[1175] Energex, *Regulatory proposal*, July 2009, pp. 205–206.

- replacement of three smaller depots
- upgrading existing sites.

Energex stated that its proposed capex program for the next regulatory control period has been developed to meet the key network challenges of growth, security compliance, refurbishment or replacement of assets and reliability.[1176]

Energex's capex forecasting methodology uses a bottom up approach.[1177] Energex developed the capex forecasts using 2007–08 as the base year.[1178]

F.3 Submissions

The AER received three submissions relating to Energex's proposed capex for the next regulatory control period, from the Energy Users Association of Australia (EUAA), Origin Energy Retail (Origin) and Queensland Council of Social Service (QCOSS).

The EUAA and QCOSS sought assurances that the capex proposed by Energex is efficient[1179] and that Energex's demand management activities are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[1180]

The EUAA observed that growth in Energex's capex between 2001–02 and 2009–10 has been much higher than growth in peak demand and customer numbers. It suggested the AER should carefully examine what has been achieved before contemplating further increases in expenditure.[1181] Origin stated that the growth in capex proposed by Energex for the next regulatory period is well above growth in peak demand and customer numbers and urged the AER to apply detailed scrutiny of the basis of the proposed increase in capex.[1182]

The EUAA stated that Energex's arguments for capex to replace ageing assets do not appear to be supported by the asset age profile.[1183]

The EUAA sought assurances that the security and reliability capex proposed by Energex is reasonable and responsible.[1184] Origin stated that it would be useful to understand when Energex will meet its N–1 security obligations.[1185]

1176 Energex, *Regulatory proposal*, July 2009, p. 210.
1177 Energex, *Regulatory proposal*, July 2009, p. 197.
1178 Energex, *Regulatory proposal*, July 2009, p. 214.
1179 EUAA, *Submission to the AER*, August 2009, p. 20; and QCOSS, *Submission to the AER*, August 2009, p. 2.
1180 EUAA, *Submission to the AER*, August 2009, pp. 20–21; and QCOSS, *Submission to the AER*, August 2009, pp. 3–4.
1181 EUAA, *Submission to the AER*, August 2009, p. 19.
1182 Origin, *Submission to the AER*, August 2009, p. 4.
1183 EUAA, *Submission to the AER*, August 2009, p. 20.
1184 EUAA, *Submission to the AER*, August 2009, p. 19.
1185 Origin, *Submission to the AER*, August 2009, p. 4.

F.4 Consultant review

The AER engaged PB to provide an independent review of the prudence and efficiency of Energex's proposed capex program.[1186]

Based on its review, PB has found Energex's proposed system capex to be prudent and efficient, except for the forecast expenditures relating to growth. PB's key findings are as follows:[1187]

- Energex's capital governance is consistent with good electricity industry practice
- the processes and procedures Energex used reflect good electricity industry practice and implementation should lead to a prudent and efficient outcome
- Energex's consideration of non-network solutions and demand management alternatives is consistent with good electricity industry practice
- the electricity demand forecasts set out in the Energex regulatory proposal have been appropriately incorporated into forecast expenditures
- Energex's proposed capex for growth has been reduced by $289 million ($2009–10), based on reduced demand forecasts as recommended by MMA.

PB's recommendations in relation to Energex's system capex are presented in table F.2.

Table F.2: PB's recommended system capex allowance for Energex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposal	1047.0	1144.9	1203.5	1229.2	1277.5	5902.1
PB adjustment to growth capex	–37.3	–43.8	–60.5	–66.9	–80.0	–288.6
PB recommendation	1009.7	1101.1	1143.0	1162.3	1197.5	5613.6

Source: PB, *Report – Energex*, October 2009, p. xiv.
Note: Totals may not add due to rounding.

For non–system capex, PB found Energex's proposed level of expenditure not to be prudent and efficient. In particular, PB found that the need and timing for the extensive proposed building program was not sufficiently demonstrated. PB recommended a reduction of $158 million ($2009–10) to the proposed $298 million ($2009–10) for land and buildings capex in the next regulatory control period. The proposed capex for Information and Communications Technology (ICT), tools and equipment and fleet were assessed as being prudent and efficient by PB.[1188]

[1186] PB, *Report – Energex*, October 2009, p. 1.
[1187] PB, *Report – Energex*, October 2009, pp. xiii–xiv.
[1188] PB, *Report – Energex*, October 2009, pp. xiv–xv.

Table F.3 presents PB's recommended non–system capex allowance for the next regulatory control period.

Table F.3: PB recommended non–system capex allowance for Energex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposal	192.3	124.8	98.4	63.2	85.0	563.7
Less PB adjustment to non–system capex	–115.0	–39.8	–16.4	9.5	3.3	–158.3
PB recommendation	77.3	85.0	82.0	72.7	88.3	405.4

Source: PB, *Report – Energex*, October 2009, p. xv.

PB's specific findings on each area of Energex's capex proposal are described in section F.5.4 of this appendix.

F.5 Issues and AER considerations

This section presents the AER's consideration of the following aspects of Energex's regulatory proposal:

- its policies, procedures and methods
- its cost estimation processes
- the application of input cost escalators
- proposed expenditure by major category
- the deliverability of the forecast capex program.

F.5.1 Policies, procedures and methods

This section examines whether Energex's capex planning practices are appropriate and provide a framework that is likely to result in prudent and efficient investment decisions. The AER considers that assessing these practices in this manner is relevant for determining whether the AER is satisfied that Energex's forecast capex reasonably reflects the capex criteria.

Energex regulatory proposal

Energex's capex planning activities are undertaken through the network development and management framework, which translates Energex's network strategies into the projects and programs that result in the development of the capex (and opex) forecasts. The network development and management framework consists of

Energex's network strategy and a range of procedures, plans, standards and policy documents.[1189]

The overall network strategy is supported by a number of subordinate documents that account for the technical standards and engineering needs of the distribution network, including in the areas of network development, reliability improvement, demand management, asset renewal, maintenance, power quality, and telecommunications and supervisory communications and data acquisition (SCADA).[1190]

Energex stated that its capex forecasting methodology uses a bottom up approach in developing a program that meets demand, security compliance, and reliability obligations while taking account of asset loads and condition. Energex has described the key elements of its capex forecasting process as follows:[1191]

- consideration of the major inputs including forecast demand and customer numbers, security and reliability obligations, and the loads and condition of current assets
- establishment of the target network performance outcomes
- preparation of a capex program, including high level cost estimates, that addresses the drivers of growth, security, asset renewal, reliability, demand management, modernisation of the network and power quality
- assessment of Energex's delivery capability
- program optimisation, including evaluation of the risk profile
- consideration of the proposed program under a balanced outcomes decision model, weighing customer expectations and the risk profile against sustainable financial imperatives
- development of the detailed works program, including options analysis, risk assessment and final project approval estimates
- approval through Energex's capital governance process.

At the operational level, the development of projects and programs including options analysis, scoping, estimation and approvals processes is undertaken in accordance with the relevant Business Management System (BMS) process document. Compliance with the BMS is monitored annually through external audit processes.[1192]

The key documents which summarise Energex's proposed capital investment plans are the network development plan for the sub–transmission network and distribution

[1189] Energex, *Regulatory proposal*, July 2009, p. 76.
[1190] Energex, *Regulatory proposal*, July 2009, p. 67.
[1191] Energex, *Regulatory proposal*, July 2009, pp. 197–198.
[1192] Energex, *Regulatory proposal*, July 2009, p. 77.

backbone, and the distribution capital plan for the distribution network, including customer driven works.[1193]

In relation to capital governance, Energex stated that its network planning and expenditure processes are subject to a three tier capital governance process including:[1194]

- high level targets and forecasts approved by the Energex Board as part of the statutory corporate plan and statement of corporate intent
- endorsement by the Energex Board of five year rolling expenditure programs and 12 month detailed programs of work as part of the network management plan
- annual budgets and delivery plans approved by the Energex Board.

The Energex Board's Network Technical Committee oversees the outcomes of the network development and management framework. Program outcomes and variations to the approved work program are monitored by the Program of Work Governance Committee comprising the Chief Financial Officer and Energex's three network general managers.[1195]

Consultant review

PB reviewed Energex's capex planning and governance policies and procedures as a critical element of assessing the prudence and efficiency of the capex proposed for the next regulatory control period. Given the impracticality of individually assessing the reasonableness of each capital investment decision represented by Energex's proposal, PB reviewed the framework in which decisions are made to determine whether the relevant policies and procedures align with good electricity industry practice and the approach taken by Energex is likely to result in appropriate expenditure.[1196]

PB developed its view on Energex's policies and procedures through a desktop review of documentation, discussions with Energex staff and as an integral part of its review of specific projects and programs of work. Reviewing policies and procedures in the context of specific proposed expenditures allowed PB to review appropriate application and implementation.[1197]

In relation to Energex's capex planning and governance policies and procedures, PB concluded that:

- Energex's capitalisation policy adopted a reasonable and pragmatic approach to classifying business expenditures, and is applied throughout the organisation in a consistent manner[1198]

[1193] Energex, *Regulatory proposal*, July 2009, pp. 67–68.
[1194] Energex, *Regulatory proposal*, July 2009, p. 76.
[1195] Energex, *Regulatory proposal*, July 2009, pp. 76–77.
[1196] PB, *Report – Energex*, October 2009, p. 8.
[1197] PB, *Report – Energex*, October 2009, p. 8.
[1198] PB, *Report – Energex*, October 2009, p. 18.

- Energex's capital governance framework was found to be consistent with good electricity industry practice and provided adequate assurance that investment decisions are likely to be prudent[1199]

- Energex's planning criteria are pragmatic, representative of good electricity industry practice, and reflect the specific conditions pertinent to Energex's area and network[1200]

- the options analysis process presents a variety of options, including a do nothing option and potential non–network solutions, and options are assessed on the basis of net present value. A sensitivity analysis of the cost drivers of each option is undertaken to ensure that the preferred option is robust in terms of changes to scope or cost[1201]

- the cost estimation processes and procedures Energex used reflect good electricity industry practice and implementation should lead to a prudent and efficient outcome[1202]

- despite limited discussion of non-network alternatives in planning proposals, Energex's consideration of efficient non-network solutions and demand management alternatives is consistent with good electricity industry practice[1203]

- the application of the demand forecasts set out in Energex's regulatory proposal has been appropriately incorporated into capex forecasts[1204]

- the application of the condition based risk management (CBRM) model to Energex's replacement and renewal capex program leads to a prudent and efficient capex proposal[1205]

- the revised network security standards that Energex proposed for the next regulatory control period represent good electricity industry practice.[1206]

AER considerations

The AER reviewed Energex's capex planning and governance framework, and sought advice from PB as to the appropriateness of the key plans, policies and procedures underpinning Energex's capex proposal. The AER did not receive any submissions that related specifically to Energex's capex planning and governance policies and procedures.

The AER notes that PB addressed specific issues regarding the formulation or application of Energex's capex planning and governance policies or procedures

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1199 PB, *Report – Energex*, October 2009, p. 24.
1200 PB, *Report – Energex*, October 2009, p. 35.
1201 PB, *Report – Energex*, October 2009, pp. 28–29.
1202 PB, *Report – Energex*, October 2009, p. 29.
1203 PB, *Report – Energex*, October 2009, p. 31.
1204 PB, *Report – Energex*, October 2009, p. 50.
1205 PB, *Report – Energex*, October 2009, p. 50.
1206 PB, *Report – Energex*, October 2009, p. 51.

through its recommendations on the prudent and efficient level of capex for each capex program. As such, the AER's general conclusions in this section as to the appropriateness of Energex's capex planning and governance policies and procedures should be read in conjunction with the discussion of the various specific elements of Energex's capex proposal.

The AER reviewed Energex's capex governance framework, including relevant documentation provided by Energex with respect to its capital budgeting, evaluation, approval, monitoring and review procedures, and delegation structures. The AER notes that Energex's capital investment planning processes are set out through a range of BMS documents, and that compliance with the BMS procedures is monitored annually through external audit processes.[1207] The AER notes the governance roles of the Energex Board's Network Technical Committee and the Program of Work Governance Committee in overseeing the outcomes of the network development and management framework, and program outcomes and variations.[1208] On the basis of its review, the AER considers Energex's capex governance framework is robust and provides adequate assurance that investment decisions are likely to be prudent and efficient.

The AER notes PB's advice that Energex's planning criteria are pragmatic, representative of good electricity industry practice, and reflect the specific conditions pertinent to Energex's area and network.[1209] Further, the AER notes that Energex's options analysis process presents a variety of options, including a do nothing option and potential non–network solutions, and those options are assessed on the basis of net present value.[1210] The AER considers that these findings support a view that Energex's capital investment planning processes are likely to provide for prudent solutions to identified network constraints.

The AER notes PB's view that the cost estimation processes and procedures Energex has used reflect good electricity industry practice and implementation should lead to a prudent and efficient outcome.[1211] The AER also notes that Energex's consideration of efficient non-network solutions and demand management alternatives is considered by PB to be consistent with good electricity industry practice.[1212] The AER further notes that all demand management initiatives proposed have been justified by Energex as efficient on the basis of positive net present value savings.[1213] The AER considers on this basis that Energex's capital investment planning processes are likely to support the identification of the efficient costs of capex requirements.

Having considered Energex's capex planning and governance framework, and advice from PB, the AER is satisfied that Energex's policies and procedures for capex planning and governance demonstrate a sufficient level of assurance and good practice such that their application is likely to lead to prudent and efficient investment

[1207] Energex, *Regulatory proposal*, July 2009, p. 77.
[1208] Energex, *Regulatory proposal*, July 2009, pp. 76–77.
[1209] PB, *Report – Energex*, October 2009, p. 35.
[1210] PB, *Report – Energex*, October 2009, p. 28.
[1211] PB, *Report – Energex*, October 2009, p. 50.
[1212] PB, *Report – Energex*, October 2009, p. 31.
[1213] Energex, *Demand Management Strategy*, June 2009, pp. 23–24.

decisions. On this basis the AER is satisfied that Energex's capex planning and governance processes are consistent with the achievement of the capex objectives.

F.5.2 Cost estimation processes

This section examines the methods adopted by Energex to estimate costs for identified investment needs in the context of determining whether the AER is satisfied that its forecast capex reasonably reflects the capex criteria.

Energex regulatory proposal

Energex stated that its estimation process for individual projects provides the platform for its capex forecast.[1214] Specifically, Energex has an estimating program that includes standard designs for network 'building blocks', including substations, overhead powerlines and underground cables. These building blocks comprise 'compatible units' (such as transformer bays), which in turn are made up of individual network components (such as civil works, isolators etc).[1215]

Energex developed the scope of individual capex projects by selecting appropriate building blocks to deliver the required network outcome. The cost of each project is then based on the estimated cost of the building blocks required.[1216]

Energex indicated that project cost estimates are reviewed at key stages in the planning, design and construction process.[1217] Specifically, 'strategic estimates' are produced at the outset of a capex program and form the basis of capex forecasts in the three to ten year time frame. 'Project approval estimates' are developed from detailed planning analysis and form the basis of capex forecasts in the zero to three year time frame. Finally, 'variation estimates' are used to adjust original project estimates and impact on capex forecasts for the next year.[1218]

Energex stated its project management system consolidates the estimated cost of individual projects into the overall capex forecast.[1219] It indicated that the standard designs in its estimating program are periodically tested and reviewed against market and industry development. Energex stated that following more than 50 years experience in management and construction of electricity infrastructure, it has developed economically efficient standard designs for network assets.[1220]

Energex noted that the unit rates used to develop its capex forecasts reflect efficient costs and are derived from competitive tendering.[1221]

Energex indicated that the unit rates used to develop its capex forecasts were independently reviewed by Evans and Peck.[1222] Evans and Peck stated that while they did not complete detailed cost benchmarking, they did perform a number of 'spot'

[1214] Energex, *Regulatory proposal*, July 2009, p. 198.
[1215] Energex, *Regulatory proposal*, July 2009, p. 199.
[1216] Energex, *Regulatory proposal*, July 2009, p. 199.
[1217] Energex, *Regulatory proposal*, July 2009, p. 198.
[1218] Energex, *Regulatory proposal*, July 2009, p. 199.
[1219] Energex, *Regulatory proposal*, July 2009, p. 199.
[1220] Energex, *Regulatory proposal*, July 2009, p. 199.
[1221] Energex, *Regulatory proposal*, July 2009, p. 195.
[1222] Energex, *Regulatory proposal*, July 2009, p. 195.

checks on Energex's unit prices, on items such as padmount uprating, pole transformer uprating and Consac cable replacement.[1223] Evans and Peck noted that there were some differences between Energex's unit prices and average unit prices available to Evans and Peck from work associated with other regulatory case preparation, but that was to be expected given the differing circumstances of DNSPs.[1224] Evans and Peck concluded that, on balance, Energex's unit rates fell within the range that Evans and Peck expected.[1225]

Costs for the units that make the 10 largest contributions to Energex's forecast capex on a volume weighted basis are presented in table F.4.

Table F.4: Energex's highest 10 capex unit costs for the next regulatory control period – confidential

Capex unit	Unit cost ($)	Total expenditure ($m, 2009–10)	Share of system capex (%)
Commercial and industrial customer connections			
Domestic and reliability (subdivision)			
Customer services			
Generic block loads (underground and overhead)			
Company initiated augmentation of 11kV and LV network			
Up-rate padmount transformers			
2nd module minor distribution works			
Re-conductor 10km 11kV overhead mains			
Replace bush pole			
Establish 110/11kV zone substation			
Total			

Source: Energex, email response AER EGX 15, 23 September 2009, confidential.

[1223] Evans and Peck, *Energex Review of 2010/11 to 2014/15 Submission to the Australian Energy Regulator for Compliance with National Electricity Rules*, June 2009, p. 28.
[1224] Evans and Peck, *Energex Review*, June 2009, p. 28.
[1225] Evans and Peck, *Energex Review*, June 2009, p. 28.

Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of Energex's capex proposals.

While not required to provide a comprehensive benchmarking review of unit costs, PB was required, as part of developing its view on the efficiency of investment decisions, to undertake a review of unit costs where it considered this was necessary.

In order to make this determination, PB adopted a phased approach, involving initial broad coverage of the capex proposal before undertaking a more detailed examination of key issues as required.[1226]

PB reviewed the estimating computer program used by Energex to develop cost estimates for its capex program. PB noted that Energex's approach includes the development of building blocks used in the construction of the network and that these include all labour, material and contract work. PB also noted that Energex's cost estimating system is used to prepare estimates for various stages in the planning, design and construction process and that it allows for variation of estimates where known factors make it likely that the original approval will be exceeded.[1227]

In addition to reviewing Energex's proposal and supporting documentation, PB conducted two rounds of detailed discussions with Energex staff, including discussion of the cost estimation process for specific projects. PB found a consistent approach had been applied to the reviewed projects and that Energex had included sensitivity analysis on changes in cost in the cost estimating process.[1228]

Based on its review, PB concluded that the processes and procedures Energex has used to estimate costs in developing its capex forecasts reflect good electricity industry practice and that their implementation should lead to a prudent and efficient outcome.[1229]

AER considerations

The AER notes Energex's view that the unit rates used to develop its capex forecasts reflect efficient costs and are derived from competitive tendering. The AER considers that reliance on external competitive tender processes for the provision of capex related materials and services is likely to result in efficient costs being incurred by a DNSP.

The AER notes that Energex's cost estimates are reviewed at key stages in the planning, design and construction process and that the standard designs in its estimating program are periodically tested and reviewed against market and industry developments. The AER therefore considers that Energex's cost estimation system appears well designed to provide efficient cost estimates.

[1226] PB, *Report – Energex*, October 2009, p. 3.
[1227] PB, *Report – Energex*, October 2009, p. 29.
[1228] PB, *Report – Energex*, October 2009, p. 29.
[1229] PB, *Report – Energex*, October 2009, p. 29.

The AER notes Evans and Peck's conclusion that, on balance, Energex's unit rates fall within the range that Evans and Peck expected. While Evans and Peck did not complete a detailed cost benchmarking exercise, they did perform a number of 'spot' checks across a broad range of Energex's unit prices. The AER notes PB's general findings about the robustness and consistent application by Energex of its policies and procedures. Based on this, the AER considers that it is reasonable to draw the general conclusion from Evans and Peck's spot checks that Energex's unit costs are efficient.

The AER also notes PB's conclusion that the processes and procedures Energex used to estimate costs for its capex forecasts reflect good electricity industry practice and that their implementation should lead to a prudent and efficient outcome.

Having considered Energex's forecast capex program and cost estimation processes, and advice from PB and Evans and Peck, the AER is satisfied that Energex's cost estimation processes for capex reflect a realistic expectation of cost inputs and are therefore likely to result in efficient cost forecasts. On this basis the AER is satisfied that Energex's cost estimation processes are consistent with the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

F.5.3 Application of input cost escalators

This section examines whether the cost escalators used by Energex to develop its capex proposal reflect a realistic expectation of input costs required to meet the capex objectives, in the context of determining whether the AER is satisfied that Energex's forecast capex reasonably reflects the capex criteria. While cost escalation affects capex sub-categories discussed in this chapter, the impacts of cost escalation, including any adjustments required by the AER, are treated in aggregate in this section only.

Energex regulatory proposal

Energex applied input cost escalation rates for labour, contractor and material costs to its forecast capex program to adjust for the real cost increases expected by Energex in the next regulatory control period.

Energex engaged KPMG to develop escalation rates for the cost of labour, materials and contractors.[1230] KPMG completed its report in March 2008 and provided another report to Energex in May 2009 which updated escalation rates for materials.

Initially KPMG recommended annual escalation rates for nominal labour, materials and contractor costs over the next regulatory period, based on a combination of:[1231]

- moving average estimation
- classical regression analysis
- structural time series analysis

[1230] Energex, *Regulatory proposal*, July 2009, p. 176.
[1231] Energex, *Regulatory proposal*, July 2009, appendix 12.6, KPMG, Final report on escalation rates for labour, materials and contractors, p. 1.

- anecdotal evidence.

In its May 2009 report, KPMG calculated a 'reasonable point estimate' of the annual increase in the real value of Energex's materials costs over the period 2007 to 2015 of 11.1 per cent.[1232] However, based on qualitative evidence which indicated significant variation in the escalation rates in 2008 and 2009, KPMG recommended a real escalation rate for materials of zero per cent and suggested that this be reviewed closer to the start of the next regulatory control period.[1233] Energex stated that it would monitor input data over 2009 and consider the need for revising its materials escalation rate in response to the AER's draft determination.[1234]

KPMG's approach to calculating cost escalation rates is discussed in more detail in appendix H.

The escalation rates applied by Energex to develop its capex forecasts are shown in table F.5.

Table F.5: Forecast real increases for Energex's key cost categories (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Labour costs (internal and contract)	2.03	3.05	3.05	3.05	3.05	3.05	3.05
Construction costs	1.53	2.05	10.20	10.20	10.20	10.20	10.20
Land and easements	1.53	2.05	2.00	2.00	2.00	2.00	2.00
Materials costs (includes motor vehicles, plant and equipment)	1.53	2.05	0.0	0.0	0.0	0.0	0.0

Source: 2008–09: Energex, email response AER.EGX.26, 5 October 2009.
2009–10 to 2014–15: Energex, *Regulatory proposal*, July 2009, table 1 in RSD 2.3.10(1), nominal values converted to real using Energex's forecast for annual CPI of 2.45 per cent.

The impact of Energex's proposed input cost escalators is illustrated in table F.6.

[1232] Energex, *Regulatory proposal*, July 2009, appendix 12.7, KPMG, Final report on escalation rates for other asset categories and materials, p. 3.

[1233] Energex, *Regulatory proposal*, July 2009, appendix 12.7, KPMG, Final report on escalation rates for other asset categories and materials, p. 29.

[1234] Energex, *Regulatory proposal*, July 2009, p. 178.

Table F.6: Impact of Energex's cost escalator factors ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base capex ($m 2007–08)	1130.4	1151.5	1168.0	1149.0	1203.4	5802.3
Escalation adjustment	52.7	60.9	75.8	86.2	99.1	374.7
Inflation adjustment	56.3	57.3	58.2	57.2	59.9	289.0
Total capex with real cost escalators	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0

Source: Energex, email response AER.EGX.22, 5 October 2009.
Note: Totals may not add due to rounding.

Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of Energex's expenditure proposals. PB was not required to assess forecast rates of growth in Energex's input costs. However, as part of its review, PB was required to ensure that forecast changes in input costs have been appropriately reflected in the cost escalation calculations performed by Energex in forecasting capex.

PB noted that the application of escalators within Energex's enterprise systems could not be directly verified. As a result, PB was provided with a model built by Energex to demonstrate the application of escalators within its cost estimating systems to the relevant expenditure type.[1235]

PB reviewed Energex's escalator model and found that:[1236]

- the model provides the breakdown of forecast system capex into asset categories (such as distribution transformers and sub-transmission lines) and the breakdown of each of these asset categories into expenditure types (such as materials and labour)
- the cost escalators are applied to the correct expenditure type categories and therefore the cost escalators are inherently weighted correctly according to the value of each expenditure type
- the expenditures at the asset category level sum to amounts that equal the total proposed expenditure.

Based on these findings, PB concluded that it was satisfied with the treatment of escalators within the Energex model and confident that the model represents the impact of escalation within Energex's enterprise systems.[1237]

[1235] PB, *Report – Energex*, October 2009, p. 11.
[1236] PB, *Report – Energex*, October 2009, p. 11.
[1237] PB, *Report – Energex*, October 2009, p. 11.

AER considerations

The AER notes that, because the application of escalators within Energex's enterprise systems could not be directly verified, PB's review was limited to an assessment of the escalator model provided by Energex. The AER notes that this model demonstrates cost escalation from 2009–10 to 2014–15.[1238]

The AER has considered PB's review of the cost escalator model and is satisfied with PB's findings in relation to Energex's escalation of costs from 2009–10 to 2014–15.

Energex indicated that while all of its expenditure estimates had been costed in 2008–09 dollars, its base year for calculating capex costs was 2007–08.[1239] However, as with the model provided to PB, Energex only provided cost escalators for 2009–10 to 2014–15.[1240]

Energex has since confirmed that its capex forecasts were based on 2007–08 costs which were escalated by the cost escalators presented in table F.5.[1241]

The AER's detailed consideration and conclusions on Energex's input cost escalators, and the methodologies underpinning those escalators, are set out at appendix H to this draft decision. The AER has not accepted the methodologies used to develop Energex's real cost escalators.

Energex engaged KPMG to determine escalation rates for cost inputs. KPMG defined internal labour as wages which are determined in Energex's enterprise bargaining agreement (EBA) and external labour (i.e. contract labour) as wages that are not determined by Energex's EBA.[1242] For internal labour, KPMG calculated a constant wage growth forecast for the duration of the next regulatory control period based on a composite index of wage data[1243] from the mining industry, the energy, gas and water industries (adjusted to reflect EBA impacts), and construction sectors. Each sector was attributed an equal weighting in the composite index.[1244] KPMG applied a similar approach to develop its contract labour escalator, excluding EBA impacts. Energex did not use a general labour cost escalator in its regulatory proposal.

As discussed in detail in appendix H, the AER does not consider Energex's escalation rates for labour costs are acceptable because, amongst other things, constant wage growth forecasts do not accurately represent the volatility of the current market and the forecasts do not reflect the most recently available data.

[1238] Energex, email response to PB question PB.EGX.MW.37, capex model, 11 August 2009, confidential.

[1239] Energex, *Regulatory proposal*, July 2009, RIN supporting documentation, RSD 2.3.10(1), Expenditure escalation processes, p. 3.

[1240] Energex, *Regulatory proposal*, July 2009, RIN supporting documentation, RSD 2.3.10(1), Expenditure escalation processes, table 1, p. 3.

[1241] Energex, email response to AER request AER.EGX.26, received 5 October 2009, confidential.

[1242] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, p. 4.

[1243] ABS, *Labour price index*, Australia, Catalogue Number 6345.0. See: <www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/6345.0Jun%202009?OpenDocument>.

[1244] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, p. 37.

For materials costs, KPMG calculated a real escalation rate for the next regulatory control period but recommended that it not be applied due to market volatility. Energex applied real escalation rates of 1.53 per cent and 2.05 per cent in 2008–09 and 2009–10 and zero real cost escalation from 2010–11 to 2014–15.[1245]

As discussed in detail in appendix H, the AER does not consider Energex's escalation rates for materials costs are acceptable because they do not reflect actual and forecast changes in materials costs, most notably significant decreases in materials costs in 2008–09 and 2009–10.

The AER requested Energex to model the impacts of the AER's decisions in relation to cost escalation. Energex advised that the adjustment to forecast capex is a reduction of $372 million.[1246]

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's cost escalation reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed capex by $372 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for capex to comply with the NER. In coming to this view the AER has had regard to the capex factors.

F.5.4 Review by expenditure type

F.5.4.1 Growth capex

Energex proposal

Energex has proposed growth capex of $2613 million ($2009–10). Total growth capex, which includes both customer initiated capital works (CICW) and corporate initiated augmentation (CIA) expenditure, represents approximately 40 per cent of the total forecast capex program. Table F.7 sets out Energex's proposed growth capex for the next regulatory control period.

Table F.7: Energex's proposed growth capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Corporate initiated augmentation	186.6	219.1	302.6	334.7	400.1	1443.1
Customer initiated capital works	230.2	237.9	230.4	234.6	237.1	1170.1
Total growth capex	416.7	457.0	533.0	569.3	637.2	2613.2

Source: Energex, *Regulatory proposal*, July 2009, RIN supporting document 2.2.1(2).
Note: Totals may not add due to rounding.

[1245] Energex, *Regulatory proposal*, July 2009, RIN supporting documentation, RSD 2.3.10(1), Expenditure escalation processes.
[1246] Energex, response to the AER, 11 November 2009, confidential.

Energex's proposed growth capex of $2613 million has been derived from a baseline growth capex forecast developed on the basis of network demand forecasts prepared in July 2008.[1247] At that time, annual network peak demand growth was forecast to be 4.36 per cent over the next regulatory control period.[1248]

Energex made an adjustment to the baseline growth capex forecast to account for a reduction in expected network demand since the July 2008 demand forecasts were prepared, due to the impacts of the global financial crisis (GFC) and the implementation of proposed demand management initiatives.[1249] Energex's proposed growth capex program therefore reflects a downwards adjustment of $241.7 million from the original baseline forecast, which it considered proportional to the anticipated demand reduction arising from these factors.[1250]

Approximately 55 per cent of the proposed growth related capex is attributed to CIA work as described in Energex's network development plan. This plan provides high level estimates of the capital works needed to meet the augmentation requirements of the sub-transmission and distribution networks in the three to 10 year timeframe. Detailed sub-transmission and distribution network planning processes then form the basis of project approval estimates forecasting capex requirements in the zero to three year timeframe.[1251]

The remaining 45 per cent of Energex's proposed growth related capex is attributable to CICW expenditure. This expenditure relates to work required to service new customer connections, including designing and constructing connection assets and connecting customers to the network. Capex related to the design and construction of connection assets for larger commercial and industrial customers is not included in this forecast as this is classified as an alternative control service.[1252]

Energex estimated that it will recover approximately 30 per cent of total CICW expenditure through customer contributions, in accordance with its capital contributions policy. Energex's forecast of the level of customer contributions for gifted assets is based on anticipated growth in subdivision lots and increased contribution rates following an update to the capital contributions policy. For cash contributions, Energex's forecast is based on historical trends, adjusted for any known material changes.[1253]

Consultant review

PB reviewed Energex's proposed growth related capex for the next regulatory control period, including both the CIA and CICW proposed capex. Its review considered the drivers of these categories of expenditure and the application of key policies and procedures including Energex's planning criteria, options analysis and cost estimation

[1247] Energex, *Regulatory proposal*, July 2009, p. 149.
[1248] Energex, *Regulatory proposal*, July 2009, p. 137.
[1249] Energex, *Regulatory proposal*, July 2009, p. 149.
[1250] Energex, *Regulatory proposal*, July 2009, pp. 150, 193.
[1251] Energex, *Regulatory proposal*, July 2009, pp. 197–199.
[1252] Energex, *Regulatory proposal*, July 2009, p. 202.
[1253] Energex, *Regulatory proposal*, July 2009, pp. 269–270.

procedures. PB also reviewed Energex's consideration of non-network alternatives and the application of the demand forecast.[1254]

A separate review of Energex's peak demand forecasts was undertaken for the AER by McLennan Magasanik Associates (MMA). The outcomes of this review are discussed in detail in chapter 6 of this draft decision. PB took account of MMA's recommendations on Energex's peak demand forecast in making its recommendations on Energex's proposed CIA expenditure.

PB found that Energex's planning criteria are pragmatic and acknowledge a level of risk based on characteristics of the Energex network. The application of the planning criteria was assessed through the review of five specific projects and three generic programs of work. PB considered the planning criteria represent good electricity industry practice, and reflect the specific conditions pertinent to Energex's area and network.[1255]

In regard to Energex's cost estimation processes for growth related capex, PB found that the cost estimation processes and procedures used by Energex reflect good electricity industry practice, and that implementation should lead to a prudent and efficient outcome. PB found that a consistent approach to cost estimation had been applied across the projects reviewed.[1256]

PB reviewed the options analysis and selection undertaken by Energex in seven plans and associated proposals. PB found that the options analysis presented a variety of options, and that options were assessed on the basis of net present value. PB noted that potential non–network solutions were considered as part of the options analysis, though no viable non–network solutions were identified for the specific projects reviewed. PB also noted that, in addition to the net present value analysis, Energex undertook a sensitivity analysis of the cost drivers of each option to ensure that the preferred option was robust in terms of changes to scope or cost.[1257]

In reviewing the extent to which Energex considers efficient non–network alternatives to address identified network constraints, PB found that although non–network alternatives were discussed there was little detail provided as to which non–network alternatives were examined or why alternatives were considered unsuitable. On further analysis, PB agreed with Energex that non–network solutions were unsuitable for the specific projects reviewed.[1258] PB noted that although the application of the regulatory test had not proven successful for Energex in soliciting proposals for non–network alternatives, Energex had nevertheless been proactive in pursuing other non–network alternatives in the form of demand management. PB concluded that Energex's consideration of non–network solutions and demand management alternatives is consistent with good electricity industry practice.[1259]

1254 PB, *Report – Energex*, October 2009, pp. 26–31.
1255 PB, *Report – Energex*, October 2009, p. 35.
1256 PB, *Report – Energex*, October 2009, p. 29.
1257 PB, *Report – Energex*, October 2009, pp. 28–29.
1258 PB, *Report – Energex*, October 2009, p. 31.
1259 PB, *Report – Energex*, October 2009, p. 31.

PB indicated that the network development plans and area plans contained a high level of detail that demonstrated relevant processes and procedures had been followed. PB noted that an appropriate approval had been sought on all projects reviewed, and the level of detail provided was sufficient to allow the approver to make an informed decision.[1260] PB found that the documentation for the programs of work and projects reviewed included thorough supporting data, and provided detail that addressed scope, options, timing and cost. PB concluded that the growth capex proposal was prudent and efficient in this respect.[1261]

In relation to the application of demand forecasts, PB found that the demand forecast set out in Energex's regulatory proposal had been appropriately incorporated into Energex's forecast expenditures.[1262] However, MMA's review of Energex's peak demand forecasts found that the forecasts were likely to be overstated to the extent of 200MW to 300MW.[1263] PB interpolated this to represent the equivalent of one year of peak demand related expenditure, and recommended that Energex's proposed growth capex be reduced by this amount to reflect that the level of system demand is expected to reach the forecast level one year later than predicted by Energex. In order to smooth the impact of this one year delay in expenditure across the five years of the next regulatory control period, PB recommended that Energex's proposed CIA capex be reduced by 20 per cent in each year, amounting to a total reduction of $289 million.[1264]

PB also reviewed Energex's proposed CICW expenditure, and noted that Energex had forecast an annual increase in customer numbers of 2.2 per cent and a variation in proposed expenditures of plus or minus 3 per cent per year. PB considered the relationship between these figures to be not unreasonable.[1265] PB also reviewed two programs of expenditure within the CICW category and found the main driver of expenditure to be forecast customer numbers, with forecasts based on historical levels of connections adjusted for the impact of the GFC. PB noted that the reduction in the number of connections forecast by Energex was equivalent to the observed reduction in dwelling approvals recorded in data from the Australian Bureau of Statistics.[1266]

AER considerations

The AER reviewed Energex's growth related capex proposal for the next regulatory control period, including both the CIA and CICW capex. The AER considered the documentation provided by Energex in support of its regulatory proposal, and sought advice from PB as to the prudence and efficiency of the proposed expenditures.

The AER notes that growth capex accounts for approximately 40 per cent of the total forecast capex program and is forecast to increase by approximately 29 per cent from the current regulatory control period.[1267]

[1260] PB, *Report – Energex*, October 2009, p. 28.
[1261] PB, *Report – Energex*, October 2009, p. 35.
[1262] PB, *Report – Energex*, October 2009, p. xiv.
[1263] MMA, *Review of Energex's maximum demand forecasts*, September 2009, p. 4.
[1264] PB, *Report – Energex*, October 2009, pp. 32–33.
[1265] PB, *Report – Energex*, October 2009, pp. 33–34.
[1266] PB, *Report – Energex*, October 2009, pp. 34–35.
[1267] PB, *Report – Energex*, October 2009, p. 25.

In relation to Energex's policies and procedures for planning the proposed growth capex, the AER notes PB's findings that:

- Energex's planning criteria are pragmatic, represent good electricity industry practice, and reflect the specific conditions pertinent to Energex's area and network[1268]
- the options analysis process presents a variety of options, including a do nothing option and potential non–network solutions, and options are assessed on the basis of net present value. A sensitivity analysis of the cost drivers of each option is undertaken to ensure that the preferred option is robust in terms of changes to scope or cost[1269]
- the cost estimation processes and procedures used by Energex reflect good electricity industry practice, and their implementation should lead to a prudent and efficient outcome[1270]
- the network development plans and area plans contain a high level of detail that demonstrates relevant processes and procedures had been followed[1271]
- appropriate approval had been sought on all projects reviewed, and the level of detail provided was sufficient to allow the approver to make an informed decision.[1272]

The AER considers that these findings support a view that the need, timing and efficiency of the proposed expenditures have been appropriately established by Energex. The AER is therefore satisfied that, with the exception of Energex's demand forecasts, the forecast growth related capex reflects the efficient costs that a prudent operator in the circumstances of Energex would require to achieve the capex objectives set out in the NER.

The AER notes that peak demand growth is a key driver of growth related expenditure, and that Energex forecast annual peak demand growth of 4.36 per cent in the next regulatory control period.[1273] The AER received submissions from the EUAA and Origin questioning the relationship between the historical and proposed growth in Energex's capex and growth in peak demand and customer numbers. These submissions urged the AER to apply detailed scrutiny to the basis of the proposed increase in capex.[1274]

In this regard, the AER sought advice from MMA about the reasonableness of Energex's peak demand forecasts, and from PB about whether these forecasts had been appropriately applied by Energex in the preparation of its capex proposal. The

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[1268] PB, *Report – Energex*, October 2009, p. 35.
[1269] PB, *Report – Energex*, October 2009, p. 28.
[1270] PB, *Report – Energex*, October 2009, p. 29.
[1271] PB, *Report – Energex*, October 2009, p. 28.
[1272] PB, *Report – Energex*, October 2009, p. 28.
[1273] Energex, *Regulatory proposal*, July 2009, p. 137.
[1274] EUAA, *Submission to the AER*, August 2009, p 19; and Origin, *Queensland DNSPs*, August 2009, p. 4.

AER notes PB's view that the demand forecast set out in Energex's regulatory proposal has been appropriately incorporated into forecast expenditures.[1275] However, the AER notes the advice from MMA that Energex's peak demand forecasts are overstated to the extent of 200MW to 300MW.[1276]

As discussed in chapter 6 of this draft decision, the AER has concluded that Energex's forecast of maximum demand does not provide a realistic expectation of the demand forecast required to achieve the capex objectives set out in the NER. The AER is therefore not satisfied that Energex's forecast demand related capex reasonably reflects a realistic expectation of the demand forecast. On this basis, the AER considers it appropriate that Energex's proposed demand related CIA capex be reduced to account for Energex's overestimation of forecast maximum demand in the next regulatory control period.

The AER notes PB's recommendation that Energex's proposed demand related CIA capex be reduced by 20 per cent in each year of the next regulatory control period, to reflect a smoothed reduction in CIA capex equivalent to one year of peak demand related expenditure. The AER considers such an approach to be reasonable for estimating, from a top down perspective, the level of CIA capex which reasonably reflects a realistic expectation of forecast demand. The AER requested Energex model the impact of the AER's decision on growth capex. Energex advised that the adjustment to forecast growth capex is a reduction of $289 million.[1277]

The AER received submissions from the EUAA and QCOSS seeking assurances that Energex's demand management activities are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[1278] The AER reviewed the extent to which Energex has considered, and made provision for, efficient non–network alternatives in its demand driven capex proposal, and also sought PB's advice in this regard.

The AER notes PB's finding that, despite the limited discussion of efficient non–network alternatives in the specific planning proposals examined, Energex's consideration of non–network solutions and demand management alternatives is consistent with good electricity industry practice.[1279] The AER notes that PB agreed with Energex's assessment as to the viability of non–network alternatives in each of the specific projects reviewed.[1280]

The AER reviewed Energex's Demand Management Strategy and found that Energex had identified examples of both broad based and targeted demand management initiatives.[1281] The AER notes that all demand management initiatives proposed had been justified by Energex as being efficient on the basis of positive net present value

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1275 PB, *Report – Energex*, October 2009, p. xiv.
1276 MMA, *Review of Energex's maximum demand forecasts*, September 2009, p. 4.
1277 Energex, response to the AER, 11 November 2009, confidential.
1278 EUAA, *Submission to the AER*, August 2009, pp. 20-21; QCOSS, *Submission to the AER*, August 2009, pp. 3–4.
1279 PB, *Report – Energex*, October 2009, p. 31.
1280 PB, *Report – Energex*, October 2009, p. 28.
1281 Energex, *Demand Management Strategy*, June 2009, p. 20.

savings.[1282] The AER notes that Energex created a list of preferred suppliers to provide non–network solutions in association with regulatory test processes, with the aim of enhancing the effectiveness of those processes.[1283]

On the basis of its review, and the advice from PB, the AER is satisfied that Energex has appropriately considered, and made provision for, efficient non–network alternatives in its demand driven capex proposal, and that Energex is in line with good electricity industry practice in this regard.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's growth related capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed growth capex by $289 million[1284] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

F.5.4.2 Replacement and renewal capex

Energex regulatory proposal

Energex forecast an amount of $1165 million ($2009–10) for replacement and renewal capex during the next regulatory control period, an increase of 271 per cent (in real terms) compared to the current regulatory control period. Forecast replacement and renewal capex represents approximately 18 per cent of Energex's total forecast capex program. Table F.8 sets out the proposed asset replacement and renewal capex for each year of the next regulatory control period.

Table F.8: Energex's proposed asset replacement and renewal capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement/renewal	160.5	255.7	212.9	280.2	256.0	1165.3

Source: Energex, *Regulatory proposal*, July 2009, p. 209.

Energex stated that high demand growth in south east Queensland has resulted in capex programs focused on meeting demand rather than on asset replacement.[1285] Energex noted that it has now increased its focus on the condition of assets that were installed in the 1960s and are approaching the end of their forecast lives.[1286] Further, it stated that many assets installed in the 1980s are moving into the latter stages of forecast life and, depending on service conditions, may need refurbishment or replacement.[1287]

1282 Energex, *Demand Management Strategy*, June 2009, pp. 23–24.
1283 Energex, *Demand Management Strategy*, June 2009, p. 17.
1284 See table F.14 for the treatment of the indirect cost component of this deduction.
1285 Energex, *Regulatory proposal*, July 2009, p. 216.
1286 Energex, *Regulatory proposal*, July 2009, p. 216.
1287 Energex, *Regulatory proposal*, July 2009, p. 203.

Energex used its CBRM methodology to develop a program to replace higher risk assets prior to anticipated failure. Asset renewal is coordinated with the growth and security compliance programs.[1288] Assets not included in these programs are included in the asset replacement and refurbishment program.

The CBRM methodology determines the probability of asset failure based on the following factors:[1289]

- age of asset and expected life
- actual performance
- operational performance
- environmental conditions
- manufacturer and specification.

The key components of the forecast replacement and renewal program include:[1290]

- programs targeting distribution network equipment such as 11kV ring main units, air break switches, pole mounted plant and replacement of timber cross–arms with wide trident steel supports
- a replacement program to address failures in the tee joint to the service pillar of low voltage consac cable
- replacement of low voltage open wire mains on timber cross–arms
- renewal or replacement of poles supporting powerlines
- refurbishment of 11kV feeders
- replacement and refurbishment of sub–transmission 33kV and 110kV lines
- a program focussed on bulk supply and zone substation plant including transformers, switchgear and ancillary equipment
- refurbishment and replacement of telecommunications and SCADA equipment.

Consultant review

PB noted that following the Electricity Distribution and Service Delivery Review (EDSD Review), Energex adopted the CBRM model to forecast asset replacement.[1291] Energex's internal planning processes review the model's forecast asset replacements to ensure that asset condition is the replacement driver,

[1288] Energex, *Regulatory proposal*, July 2009, p. 203.
[1289] Energex, *Regulatory proposal*, July 2009, pp. 71–72.
[1290] Energex, *Regulatory proposal*, July 2009, p. 204.
[1291] PB, *Report – Energex*, October 2009, p. 37.

maintenance regimes to extend asset life are also considered at this stage of the process. PB considered Energex's processes and procedures reflect good electricity industry practice and would lead to a prudent and efficient outcome.[1292]

PB noted the CBRM model calculates the most economical time to replace an asset, being the point where the sum of the depreciated value of an asset and the cost of the increased risk associated with the asset is at a minimum.[1293] Model inputs include technical inputs, constants and risk related inputs. PB examined these elements of Energex's CBRM model to understand how they drive the results. Specifically, PB examined the input weightings applied in the model and the application and value of risk.[1294]

PB found the technical inputs include a combination of samples and condition information gathered by field staff. Constants included locational factors such as proximity to the ocean, CBD, urban, rural and indoor versus outdoor locations. PB noted the weightings of these inputs were derived in conjunction with EA Technology—the CBRM model developer.[1295] Energex also tailored the model by including additional weightings for certain areas within south east Queensland. (For example, Energex identified that the trade coast area at the mouth of the Brisbane River warranted a new risk category due to the existence of petrochemical type customer loads). The additional weightings were established in conjunction with EA Technology and reflect the differing needs of these areas.[1296]

PB reviewed a number of risk inputs for the model. It found that Energex applied two values to customer reliability in the form of $/SAIDI minute lost and $/MWh of energy at risk. The $/SAIDI minute lost is applied in areas where the loss of an asset would result in the loss of supply to customers.[1297] The $/MWh amount is applied where the loss of an asset would not result in an outage but nonetheless puts the network at risk.[1298]

PB found the variable inputs to the CBRM model (specifically around the allocation of risk and the value of risk) were well supported and clearly identified.[1299] PB reviewed the source of the independent reports used to establish the value of lost load and value of customer reliability. PB found the values used were appropriate for Energex's business.[1300]

PB requested that Energex run a study of transformer replacements under a scenario based on age only for comparison with the CBRM model output. The aim of this study was to determine if a condition based approach would reduce the number of replacements and therefore the cost of replacements compared with a simplistic age based approach. A comparison was made between an aged based renewal program

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1292 PB, *Report – Energex*, October 2009, p. 38.
1293 PB, *Report – Energex*, October 2009, p. 38.
1294 PB, *Report – Energex*, October 2009, p. 38.
1295 PB, *Report – Energex*, October 2009, p. 39.
1296 PB, *Report – Energex*, October 2009, p. 39.
1297 PB, *Report – Energex*, October 2009, pp. 39–40.
1298 PB, *Report – Energex*, October 2009, p. 40.
1299 PB, *Report – Energex*, October 2009, p. 41.
1300 PB, *Report – Energex*, October 2009, p. 41.

and CBRM for Energex's 33kV transformer population. PB noted the results of this study show the CBRM model predicted 20 per cent fewer replacements than an age based approach would give for this particular asset class.[1301]

Additionally, PB requested information on transformer replacements that, based on model prediction, would occur earlier than if an age based approach were taken. The model predicted the end of life for a transformer at the Loganholme substation after just 23 years due to decomposing insulation within the transformer.[1302] An example was also provided to show that the model recommended the delay in replacement of another transformer at a different location based on its condition rather than age resulting in an additional fours years of reliable service from the transformer.[1303]

PB concluded that with the level of detail provided around the inputs to the model, supporting documentation on the establishment of value of risk, the application of weightings and load at risk, the application of the CBRM model to predict Energex's replacement and renewal program leads to a prudent and efficient replacement expenditure proposal.[1304]

PB recommended that the proposed capex for the asset replacement and renewal be accepted with no changes.[1305]

AER considerations

In considering Energex's asset replacement and renewal capex, the AER relied on PB's review and conducted its own high level assessment of the proposed expenditure.

The AER notes that Energex has a large number of assets that are approaching the end of their forecast life. Energex has increased its focus on a condition based risk management approach for asset replacement and renewal rather than on the age of the asset alone. This allows Energex to replace assets of poor condition prior to anticipated failure.[1306]

PB's analysis demonstrated the value in considering a multitude of factors when planning asset replacement. While asset age may be an indicator of asset condition and therefore likely performance, based on PB's review of transformers, assets may need to be replaced earlier or later than the timeframes indicated on nameplates. The AER notes the CBRM model is capable of predicting this replacement. Further, when compared to a purely age based transformer replacement regime, the condition based approach resulted in 20 per cent fewer replacements. The AER considers the outcome of PB's comparison of transformer replacement based on age and then condition demonstrates the efficiency of a condition based replacement program over one based solely on asset age.

[1301] PB, *Report – Energex*, October 2009, p. 40.
[1302] PB, *Report – Energex*, October 2009, pp. 40–41.
[1303] PB, *Report – Energex*, October 2009, p. 41.
[1304] PB, *Report – Energex*, October 2009, p. 41.
[1305] PB, *Report – Energex*, October 2009, p. 41.
[1306] Energex, Regulatory proposal, July 2009, p. 216.

The CBRM model is used to predict asset replacement in the longer term and Energex's planning processes confirm that replacement is required (on the basis of condition) and ensure that various site works are aligned. Where work has been brought forward to align site works a cost benefit analysis is undertaken.[1307] The AER considers Energex's approach to planning and processes for asset replacement are prudent and efficient.

EA Technologies stated that its CBRM methodology has been applied many times assisting electricity network companies around the world to deliver effective asset related risk management.[1308] The CBRM model calculates the most economical time to replace an asset by determining the point where the sum of the depreciated value of the asset and the cost of the increased risk associated with the asset is at a minimum.[1309] Several risk factors are considered including the risk of reduced network performance, safety, environmental impact and opex related risk. PB reviewed these risk factors as well as other inputs and concluded that the application of the CBRM model leads to a prudent and efficient replacement capex proposal.[1310] The AER has not conducted a detailed review of the CBRM model but notes its ability to predict the replacement of assets based on condition, physical location and the risk to its network. The AER has accepted PB's advice that its use is likely to lead to prudent and efficient asset replacement.

The AER notes the EUAA's concerns that Energex's asset age profile does not support its proposed replacement and renewal capex program. Energex's forecast replacement and renewal capex program is developed using its CBRM model which uses several technical inputs (such as asset age) constants (for example location and proximity to the coast) and risk related inputs which apply a value to risks such as environmental and loss of supply. Asset age is just one of a variety of inputs used to predict replacement. Asset replacement is predicted by the CBRM model based on overall condition rather than age. PB noted that where the CBRM model forecasts asset replacement the planning process will also review that replacement is based on asset condition.[1311]

The AER has reviewed the documentation provided by Energex, including the full application of CBRM written by EA Technology and responses to questions received from Energex. The AER is satisfied this documentation provides a level of detail which supports the need for asset replacement and renewal capex identified by Energex.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other material, the AER is satisfied that Energex forecast replacement capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

1307 PB, *Report – Energex*, October 2009, pp. 37–38.
1308 EA Technology Consulting, *Full application of condition based risk management with Energex*, confidential, July 2008, p. 4.
1309 PB, *Report – Energex*, October 2009, p. 38.
1310 PB, *Report – Energex*, October 2009, pp. 39–41.
1311 PB, *Report – Energex*, October 2009, p. 38.

F.5.4.3 Reliability and quality of service enhancement

Energex regulatory proposal

Energex forecast an amount of $306 million ($2009–10) for reliability and quality of service enhancement capex during the next regulatory control period, an increase of 114 per cent (in real terms) compared to the current regulatory control period. Forecast reliability and quality of service enhancement capex represents approximately 5 per cent of Energex's total forecast capex program. Table F.9 sets out Energex's proposed reliability and quality of service enhancement capex for each year of the next regulatory control period.

Table F.9: Energex proposed reliability and quality of service enhancement capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Reliability and quality of service enhancement	85.8	50.6	72.6	51.6	45.7	306.3

Source: Energex, *Regulatory proposal*, July 2009, p. 209.

Energex stated that reliability and quality of service enhancement capex is required to ensure that the average and individual feeder reliability performance remains within the levels mandated in the minimum service standards (MSS).[1312] The MSS are specified in Queensland's Electricity Industry Code (EIC) as part of Energex's licence conditions.

The major component of this capex stream is a program to improve the 11kV distribution network reliability by upgrading existing feeders and building new feeders. The aim is to improve performance and reduce the number of customers affected by an outage.[1313]

Additional components of the reliability and quality of service enhancement program include:[1314]

- installation of nine new rural substations to divide the rural distribution network into smaller sections to provide additional switching options
- installation of additional 11kV switches to reduce the number of customers affected during a supply interruption. This program includes the installation of communications systems as part of the smart network program to enable remote switching
- programs to increase undergrounding of overhead feeders and to reduce the number of overhead to underground transition points

[1312] Energex, *Regulatory proposal*, July 2009, p. 204.
[1313] Energex, *Regulatory proposal*, July 2009, p. 204.
[1314] Energex, *Regulatory proposal*, July 2009, pp. 204–205.

- improvement of reliability to critical infrastructure including hospitals and sewerage pumping stations

- installation of 'distance to fault' relays on 33kV rural feeders, wildlife proofing of the 11kV network and exposed busbar rural substations and replacement of unreliable sub-transmission assets.

Consultant review

PB conducted a high level review of Energex's network reliability investment plan. The plan indentified specific projects likely to improve network reliability.[1315] PB noted the plan aims to identify the gap between current reliability performance and future MSS and benefits arising from both capex and opex programs. Projects that result in a net positive benefit are developed.[1316] PB considered that Energex's reliability investment plan created a consistent and replicable approach to reliability and investment decisions, focused on delivering improvements.[1317] PB concluded that Energex's processes and procedures reflect good electricity industry practice and implementation of these policies should lead to a prudent and efficient capex.[1318]

To quantify the relative benefits of the proposed reliability improvements, PB compared the benefits of reliability capex in the current regulatory control period with the expected benefits resulting from the proposed expenditures. PB noted that in 2006, Energex applied for additional expenditure of $124 million to improve reliability by 13 SAIDI minutes for rural networks and 5.5 SAIDI minutes for urban networks.[1319] PB combined this information with customer numbers to calculate a weighted average cost of saving a SAIDI minute, determined to be $19.5m.[1320] PB used the same approach to analyse the forecast reliability expenditure in the next regulatory control period and calculated the cost per SAIDI minute saved to be $25.3 million.[1321] The SAIDI improvement figures for the next regulatory control period were taken from an Evans and Peck report on Energex's STPIS targets, impacts and risks.[1322]

Based on a cost per SAIDI minute saved, PB found that Energex's expenditure increased from $19.5 million per SAIDI minute saved to $25.3 million per SAIDI minute saved in the next regulatory control period. PB considered the increase in relative cost to be reasonable given that Energex has been pursuing reliability improvements since 2005–06, and hence many of the low–cost improvements have been captured in the current regulatory control period.[1323]

PB concluded that the overall program for reliability and quality of service enhancements forecast expenditure is prudent and efficient. PB recommended that the

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1315 PB, *Report – Energex*, October 2009, p. 43.
1316 PB, *Report – Energex*, October 2009, p. 43.
1317 PB, *Report – Energex*, October 2009, p. 43.
1318 PB, *Report – Energex*, October 2009, p. 43.
1319 PB, *Report – Energex*, October 2009, p. 44.
1320 PB, *Report – Energex*, October 2009, p. 44.
1321 PB, *Report – Energex*, October 2009, p. 45.
1322 Evans and Peck, *Energex: Service Target Performance Incentive Scheme Assessment of Targets, Impacts and Risks*, April 2009, pp. 24–25, confidential.
1323 PB, *Report – Energex*, October 2009, p. 45.

proposed capex for reliability and quality of service enhancement be accepted with no changes.[1324]

AER considerations

The AER notes that failure to meet the mandatory MSS is a breach of the EIC which may result in the QCA issuing warning notices, Code contravention notices or instituting of Supreme Court proceedings.[1325]

In April 2009, the QCA made its final decision on the MSS to apply to Energex for the next regulatory control period.[1326] The AER notes the reliability targets to apply in the next regulatory control period are more difficult to achieve than those applying in the current regulatory control period.[1327]

The AER also notes the analysis undertaken by PB to quantify the cost of SAIDI minutes saved as a result of Energex's proposed reliability capex. Energex's 2006 pass through application was targeted at improving SAIDI performance and was approved by the QCA in March 2007.[1328] PB's analysis indicated that the cost per SAIDI minute saved as a result of the capex approved by the QCA was $19.5 million whereas the cost per SAIDI minute saved over the next regulatory control period would be $25.3 million.[1329]

The AER notes that the cost of SAIDI minutes saved is forecast to increase in the next regulatory control period compared to the current regulatory control period. The AER also notes that Energex has proposed a capex program which includes many large scale capital intensive projects such as upgrading and building new feeders, undergrounding poorly performing overhead feeders and the installation of new substations.[1330] These types of projects require significant planning and are of a scale that would prevent them being commenced at short notice. The AER considers it reasonable that many of the low cost improvements would have been achieved by Energex in the current regulatory control period and larger projects would be targeted in the next regulatory control period. Given the more onerous MSS targets and the likelihood that many low cost improvements may have already been made, the AER considers that it is reasonable that Energex be allowed an increase in its forecast reliability capex allowance.

The AER has reviewed the documentation provided by Energex, the MSS set by the QCA, the requirements of the EIC and the advice of PB. The AER is satisfied the documentation, existence of licence conditions and the analysis conducted by PB supports the need for the reliability and quality of service enhancement capex

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1324 PB, *Report – Energex*, October 2009, p. 45.

1325 Energex, *Regulatory proposal*, July 2009, p. 128.

1326 QCA, *Review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010 – Final decision*, April 2009.

1327 QCA, *Review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010 – Final decision*, April 2009, pp. 2 and 20.

1328 QCA, *Energex application for Capital Expenditure Cost Pass–Through: Final decision*, March 2007, pp. 22–23.

1329 PB, *Report – Energex*, October 2009, pp. 44–45.

1330 Energex, *Regulatory proposal*, July 2009, p. 70.

identified by Energex. The AER considers that the reliability and quality improvement capex program is prudent and efficient.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other material, the AER is satisfied that Energex forecast reliability capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

F.5.4.4 Security compliance

Energex regulatory proposal

Energex forecast an amount of $1817 million ($2009–10) for security compliance capex during the next regulatory control period, an increase of 39 per cent (in real terms) compared to the current regulatory control period. Forecast security compliance capex represents approximately 28 per cent of Energex's total forecast capex program. Table F.10 sets out Energex's proposed security compliance capex for each year of the next regulatory control period.

Table F.10: Energex's proposed security compliance capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Security compliance	384.0	381.6	385.0	328.1	338.6	1817.4

Source: Energex, *Regulatory proposal*, July 2009, p. 209.

Energex stated that its security compliance capex is aimed at meeting N–1 security standards as recommended in the EDSD Review.[1331] Several recommendations were made in the EDSD Review including that the distribution authorities should include a requirement to meet a standard equivalent to N–1 for bulk and zone substations and for sub–transmission systems.[1332] Energex stated that an N–1 level of security, in the distribution context, would result in an outage following the failure of two elements (such as transformers, feeders etc) within the distribution system.[1333]

Energex mapped its forecast capex categories with those used by the QCA for the current regulatory control period stating that security compliance was previously captured under the corporate initiated capital works category. In the current regulatory control period, corporate initiated capital works also included capex which is now categorised as growth capex as set out in table F.11.

[1331] Energex, *Regulatory proposal*, July 2009, p. 200.
[1332] Energex, *Regulatory proposal*, July 2009, p. 54.
[1333] Energex, *Regulatory proposal*, July 2009, p. 130.

Table F.11: QCA and Energex capex categories

QCA category **current regulatory control period**	**Energex category** **next regulatory control period**
Asset replacement	Asset replacement/refurbishment
Customer initiated capital works	Growth
Corporate initiated capital works (part)	Growth
Corporate initiated capital works (part)	Security compliance
Reliability/quality improvement	Reliability
Other	Other
Non–system assets	Non–system assets

Source: Energex, *Regulatory proposal*, July 2009, p. 215.

Energex stated that its security compliance capex has been developed to address network limitations that breach security standards at the time of preparation of the capex forecast.[1334] It proposed to allocate the $1817 million ($2009–10) security compliance capex in the following manner:[1335]

- bulk supply and zone substations – $652 million
- 110kV and 33kV overhead and underground cables – $499 million
- 11kV lines and distribution equipment – $656 million
- communication and other works – $10 million.

Energex stated that its forecasts can not be scaled back to accommodate any reduction in forecast demand and were required to ensure it continued to progress towards the N–1 philosophy put in place by the EDSD Review and reported to the technical regulator through the network management plan.[1336]

Consultant review

PB stated that security related projects utilise the same governance processes as other capex projects and it found those processes would lead to a prudent and efficient outcome.[1337] PB stated that during its review it focussed on the new planning standards that were developed following the EDSD Review rather than conducting a detailed review of specific project expenditures.[1338]

[1334] Energex, *Regulatory proposal*, July 2009, p. 200.
[1335] Energex, *Regulatory proposal*, July 2009, p. 203.
[1336] Energex, *Regulatory proposal*, July 2009, p. 203.
[1337] PB, *Report – Energex*, October 2009, p. 48.
[1338] PB, *Report – Energex*, October 2009, p. 48.

PB noted that the EDSD Review made two significant recommendations for improving the security of the network:[1339]

- the Queensland government required Energex to meet a standard equivalent to N–1 for bulk and major zone substations and the sub–transmission system

- Energex's use of system assets be reduced to the level of 60 to 65 per cent from the 2004 level of 75 per cent.

PB noted that following the EDSD Review Energex commenced work improving the security of its network and engaged SKM to conduct a review of the security of supply standards used by other national and international electricity distribution utilities.[1340] PB noted that Evans and Peck was also engaged to provide a review of Energex's proposed security of supply standards to provide a link with the EDSD Review.[1341]

PB found the security standards proposed by Energex are less stringent than the standards recommended by the EDSD Review in so far as Energex operates some elements of its network at more than 50 per cent load.[1342] In the event of a fault, the post fault load may be greater than 100 per cent and as a result, load may be shed.[1343] PB noted that at the time of drafting its report to the AER, Energex had proposed its security of supply standards to the Queensland Department of Mines and Energy and Energex's proposed security of supply capex is based on the assumption that those proposed security of supply standards are accepted.[1344]

During its review, PB examined elements of the revised security of supply standards. PB noted that the residual load at risk after load transfers have occurred must not exceed 5 MVA. Energex verbally confirmed with PB that it can connect portable generation to a faulted network within four hours and that 5 MVA is the technical limit of available portable generation.[1345]

PB also examined the use of the 75 per cent normal cyclic capacity for distribution feeders. Energex confirmed with PB that the policy for the 11kV distribution feeder arrangements is based on this principle. This allows for one feeder to fail and the remaining load to be transferred to the remaining three adjacent feeders, thus loading the three remaining feeders to the maximum cyclic capacity.[1346]

PB found that the revised security standards Energex adopted represent a pragmatic approach to security in that they include a level of risk that Energex identified can be managed through prudent management practices. PB found that a level of risk is accepted in other jurisdictions in Australia and Energex has analysed other DNSPs' practices to reconcile these standards to their own environment. PB stated that this

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[1339] PB, *Report – Energex*, October 2009, p. 47.
[1340] PB, *Report – Energex*, October 2009, pp. 47–48.
[1341] PB, *Report – Energex*, October 2009, p. 48.
[1342] PB, *Report – Energex*, October 2009, p. 48.
[1343] PB, *Report – Energex*, October 2009, p. 48 and PB, email to the AER, 21 October 2009.
[1344] PB, *Report – Energex*, October 2009, p. 48.
[1345] PB, *Report – Energex*, October 2009, p. 49.
[1346] PB, *Report – Energex*, October 2009, p. 49.

represents good electricity industry practice and should lead to prudent and efficient expenditure.[1347]

PB recommended that the proposed capex for security compliance be accepted with no changes.[1348]

AER considerations

The AER notes Energex stated that the primary purpose of security compliance capex is to meet N–1 security standards and projects within this category address network limitations that breached security of supply standards at the time the forecast capex was developed.[1349] Security compliance capex aims to augment the network and reduce loading of lines and substations to a level such that failure of one component does not result in a sustained outage of supply to customers.[1350]

The AER notes that Energex considers that its security compliance projects must proceed to ensure compliance with the EDSD Review. In developing its security compliance capex program, Energex has considered its risk based on two scenarios:[1351]

- the raw load at risk if a fault were to occur in a component on the subtransmission system (the emergency cyclic capacity (ECC) load at risk)
- the load that can not be supplied following load transfers in line with the timeframes set out in the revised supply security standards (the residual load at risk).

During the next regulatory control period, Energex stated it expects to significantly reduce both the ECC and residual load at risk as a result of its security compliance capex program. For example, Energex expects to be able to reduce the raw ECC load at risk from 982MVA in 2010–11 to 580MVA in 2014–15.[1352]

Energex develops and publishes its annual network management plan (NMP) which sets out how it is managing its network to meet customer and shareholder expectations. The AER has reviewed the NMP and notes the latest NMP provides information on the current state of compliance against its security of supply standards and sets out additional capital works to progress towards compliance.[1353] While it is difficult to determine how far Energex has progressed towards full compliance with its proposed standard at this point in time, it has informed the AER that full compliance is not expected to be achieved until approximately 2017–18.[1354] This information addresses Origin's submission which indicated that it would be useful to know when full compliance is expected to be achieved.

[1347] PB, *Report – Energex*, October 2009, p. 49.
[1348] PB, *Report – Energex*, October 2009, p. 49.
[1349] Energex, *Regulatory proposal*, July 2009, p. 200.
[1350] Energex, *Regulatory proposal*, July 2009, p. 203.
[1351] Energex, *Regulatory proposal*, July 2009, p. 207.
[1352] Energex, *Regulatory proposal*, July 2009, p. 207.
[1353] Energex, *Network Management Plan – Part A, 2009/10 to 2013/14, Final*, 31 August 2009.
[1354] Energex, email to AER, 13 October 2009, confidential.

In considering Energex's proposed security compliance capex, the AER notes that the EDSD Review recommended that:[1355]

> ENERGEX be required to maintain "N–1" on all bulk supply sub-stations, zone supply sub-stations and sub-transmission feeders. Critical high voltage feeders should also meet "N–1" with the exception of those where ENERGEX can provide satisfactory evidence that this does not put significant numbers of customers at risk. Where ENERGEX chooses to use interconnection to provide "N–1" capacity for single transformer bulk or zone supply sub-stations, it should be required to demonstrate that there is adequate transfer capability to meet "N–1" in a timely manner

Further the EDSD Review recommended that Energex should adopt planning processes which will return all bulk supply substations, zone supply substations and subtransmission feeders to an N–1 philosophy over the next regulatory control period (that is, the current regulatory control period).[1356]

SKM was engaged by Energex (and Ergon Energy) to develop a security of supply standard to be applied at transmission, sub–transmission, zone substations and distribution levels on its network.[1357] It completed its final report which reviewed security of supply standards in New South Wales, Victoria, South Australia, New Zealand and the United Kingdom in March 2008.[1358] The AER notes that SKM recommended a security of supply standard which was slightly different to the one put forwarded by Energex. In its report to Energex, SKM noted that the proposed security of supply standards would have a material impact on Energex's capex program.[1359]

The AER notes that Energex also engaged Evans and Peck to review its revised security of supply standards with the view to ensuring consistency with Evans and Peck's interpretation of the EDSD Review and good industry practice.[1360] Evans and Peck noted that the standards represent the long term minimum planning targets and at the time of compiling its report, not all assets met the standards.[1361] In setting out its conclusions and recommendations, Evans and Peck noted that following the implementation of a number of safeguards, Energex's revised security of supply standards accord with the N–1 philosophy envisaged by the EDSD Review and are consistent with good industry practice.[1362] Energex has confirmed that the safeguards as recommended by Evans and Peck have been implemented and/or addressed as part of Energex's planning process or the NMP.[1363]

[1355] Queensland Department of Natural Resources, Mines and Energy, *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21st Century*, July 2004, p. 113.

[1356] QDNRME, *Detailed report EDSD Review*, July 2004, p. 172.

[1357] Energex, *Regulatory proposal*, July 2009, SKM, Energex and Ergon Energy: Security of supply standards, Final, 20 March 2008.

[1358] Energex, *Regulatory proposal*, July 2009, SKM – Service standards report, p. 1.

[1359] Energex, *Regulatory proposal*, July 2009, SKM – Service standards report, p. 27.

[1360] Energex, *Regulatory proposal*, July 2009, Evans and Peck, Energex: Review of proposed supply security standards, confidential, 19 February 2008, p. 1.

[1361] Energex, *Regulatory proposal*, July 2009, Evans and Peck, Energex: Review of proposed supply security standards, confidential, 19 February 2008, p. 1.

[1362] Energex, *Regulatory proposal*, July 2009, Evans and Peck, Energex: Review of proposed supply security standards, confidential, 19 February 2008, p. 2 and pp. 12–13.

[1363] Energex, email to AER, 16 October 2009, confidential.

The AER notes that PB found that security related capex projects utilise the same governance process as other capex projects and programs, which would lead to a prudent and efficient outcome.[1364] PB also found that Energex's proposed security standards are less stringent than the standards recommended in the EDSD Review.[1365]

The AER also notes PB's findings that the residual load at risk, which will be managed by portable generators, and the 75 per cent limit for normal cyclic capacity for feeders, represent good electricity industry practice.[1366]

The AER notes that the EUAA is concerned that the AER should satisfy itself that the proposed security capex of $1.8 billion is reasonable and responsible. PB concluded that Energex has adopted a pragmatic approach to developing its standards and the level of risk can be managed through prudent management practices.[1367] PB advised that the proposed standards are in accordance with good electricity industry practice and would lead to prudent and efficient expenditure[1368] and the AER has accepted PB's advice.

The AER has considered the proposal put forward by Energex, the analysis of SKM and the comments in the Evans and Peck report which indicated that the security of supply standards accord with the N–1 philosophy in the EDSD Review and represent good industry practice. The AER also notes PB's advice that the proposed security standards, which form the basis of the proposed security compliance capex program, represent a pragmatic approach to security of supply and results in a level of risk accepted in other jurisdictions in Australia.[1369]

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other material, the AER is satisfied that Energex forecast security compliance capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

F.5.4.5 Non–system capex

Energex regulatory proposal

Energex's proposed non–system capex of $564 million ($2009–10) includes expenditure on end–use computing assets, motor vehicles, land and buildings, and tools and equipment. Non–system capex represents approximately 9 per cent of the total forecast capex program. Table F.12 sets out Energex's proposed non–system capex by major categories.

[1364] PB, *Report – Energex*, October 2009, p. 48.
[1365] PB, *Report – Energex*, October 2009, p. 48.
[1366] PB, *Report – Energex*, October 2009, p. 49.
[1367] PB, *Report – Energex*, October 2009, p. 49.
[1368] PB, *Report – Energex*, October 2009, p. 49.
[1369] PB, *Report – Energex*, October 2009, p. 49.

Table F.12: Energex's proposed non–system capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
End–use computing assets	3.2	4.3	1.3	1.8	2.2	12.8
Motor vehicles	32.8	41.8	42.0	32.3	47.4	196.3
Land and buildings	143.0	67.8	44.4	18.5	24.7	298.4
Tools and equipment	13.3	10.9	10.7	10.6	10.7	56.2
Total non–system capex	192.4	124.8	98.4	63.2	85.0	563.7

Source: Energex, Regulatory proposal, July 2009, RIN pro forma 2.2.1.
Note: Totals may not add due to rounding.

Energex's expenditure on non–system assets is forecast to increase by $127 million ($2009–10) or 29 per cent from the current regulatory control period. Proposed non–system capex in the next regulatory control period is greater than expenditure in the current regulatory control period for motor vehicles and land and buildings, but lower for end–use computing assets and tools and equipment.[1370]

End–use computing assets

Energex has proposed to spend $13 million on end–use computing assets during the next regulatory control period, a decrease of 74 per cent from the current regulatory control period. Forecast expenditure is limited to asset replacement based on asset renewal guidelines and principles for laptop, desktop and toughbook computers. The majority of Energex's total expenditure on information and communications technology is incorporated in Energex's arrangements with SPARQ Solutions Pty Ltd (SPARQ), which are discussed in section F.5.4.6 of this appendix.[1371]

Motor vehicles

Energex has proposed to spend $196 million on motor vehicles in the next regulatory control period. This represents an increase of 4 per cent from the current regulatory control period. It stated the forecast capex for motor vehicles is limited to the replacement of existing vehicles.[1372]

Land and buildings

Energex's proposed capex for non–system land and buildings is $298 million during the next regulatory control period, a significant increase of 128 per cent from the current regulatory control period. The key proposed investments include:

- replacement of three major amenities including logistics and warehousing, training and pole depot facilities

[1370] Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
[1371] Energex, *Regulatory proposal,* July 2009, p. 206.
[1372] Energex, *Regulatory proposal*, July 2009, p. 206.

- construction of a centrally located new purpose built facility providing accommodation that minimises health and safety risks with improved field response capability to Energex's south west regions
- construction of five new regional administration centres to reduce pressure on current regional field response facilities
- acquisition of land and construction of seven unmanned sites for secure storage of critical spare parts and heavy machinery in close proximity to customers
- replacement of three smaller depots
- upgrading existing sites.

Energex submitted that the proposed land and buildings capex is required as part of a property strategy designed to address the extensive use of temporary accommodation, increased safety risks resulting from multidisciplinary uses of existing facilities, restricted office and depot facilities, and aged equipment.[1373]

Tools and equipment

Energex proposed to spend $56 million on tools and equipment in the next regulatory control period. This represents a decrease of 16 per cent from the current regulatory control period. Forecast capex in this category is derived from equipment testing and inspection management systems, and includes the acquisition and replacement of hand–held tools and safety equipment.[1374]

Consultant review

PB reviewed Energex's proposed non–system capex for the next regulatory control period. Its review encompassed a high level analysis of trends in expenditures from the current and previous regulatory control periods, and a review of the specific expenditure categories proposed by Energex. The detailed review of proposed expenditure categories undertaken by PB included consideration of relevant policies and procedures and other expenditure drivers.[1375]

In summary, PB found that Energex's proposed non–system capex was not prudent and efficient and recommended a reduction of $158 million to Energex's proposed expenditure of $564 million ($2009–10).[1376]

End–use computing assets

PB reviewed Energex's total ICT expenditure, including both the expenditure on end-use computing assets to be capitalised by Energex as well as the expenditure to be capitalised by SPARQ, which is reflected in SPARQ's service charge to Energex.[1377] The recommendations discussed in this section relate only to PB's review of

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[1373] Energex, *Regulatory proposal*, July 2009, pp. 205–206.
[1374] Energex, *Regulatory proposal*, July 2009, p. 206.
[1375] PB, *Report – Energex*, October 2009, p. 52.
[1376] PB, *Report – Energex*, October 2009, p. xv.
[1377] PB, *Report – Energex*, October 2009, p. 55.

Energex's proposed end–use computing asset capex, made up of items which Energex rather than SPARQ will continue to purchase in the next regulatory control period.

PB noted that Energex's Joint ICT Investment Plan sets out a blueprint to upgrade or replace existing ICT assets to meet operational needs, as well as to enhance and develop new capabilities. PB noted that, in general, ICT systems expenditure is driven by the discontinuation of older versions of software, business and technology changes, and the need to increase functional capabilities and performance or improve efficiency.[1378]

In reviewing Energex's proposed end–use computing capex, PB noted the significant reduction in expenditure from the previous regulatory control period and considered that trend to be appropriate given the majority of assets owned by Energex have gradually been transferred over to SPARQ.[1379]

On the basis of its review, PB found that Energex's proposed end–use computing capex is prudent and efficient.[1380]

Motor vehicles

PB reviewed Energex's proposed motor vehicles capex and found the proposed expenditure to be driven by a business as usual level of vehicle replacement expenditure, in line with forecast staff requirements.[1381]

PB reviewed Energex's fleet asset management plan and confirmed that the timing of Energex's motor vehicle expenditure is driven by need, determined on the basis of age or kilometre based criteria, and verified Energex's adherence to the policy.[1382]

PB noted that the majority of Energex's fleet procurement is undertaken by an external service provider appointed through a market tender process. PB noted that alternative expenditure options are typically considered in the vehicle procurement process.[1383]

PB concluded that Energex had demonstrated the proposed motor vehicle capex was prudent, as motor vehicles are replaced on a needs basis in line with the fleet asset management plan, and that its fleet services are run in a cost efficient manner.[1384]

On the basis of its review, PB found Energex's proposed motor vehicles capex to be prudent and efficient and recommended that the motor vehicles capex be accepted as proposed.[1385]

[1378] PB, *Report – Energex*, October 2009, pp. 57–58.
[1379] PB, *Report – Energex*, October 2009, p. 62.
[1380] PB, *Report – Energex*, October 2009, p. 74.
[1381] PB, *Report – Energex*, October 2009, p. 70.
[1382] PB, *Report – Energex*, October 2009, p. 71.
[1383] PB, *Report – Energex*, October 2009, p. 71.
[1384] PB, *Report – Energex*, October 2009, pp. 71–72.
[1385] PB, *Report – Energex*, October 2009, p. 72.

Land and buildings

PB reviewed Energex's proposed land and buildings capex for the next regulatory control period. PB found that Energex's land and buildings capex is driven by its property strategy, which sets out the plan to expand, upgrade or replace existing facilities to meet operational needs, alleviate overcrowding and improve field response capability.[1386]

PB requested business case documentation or supporting documentation for the high value individual property projects proposed by Energex. PB noted that Energex was unable to provide this documentation, including in relation to expenditure proposed for the first year of the next regulatory control period, as Energex intended to develop such documentation closer to project realisation.[1387]

PB noted that the risk assessment used by Energex to prioritise building projects did not use Energex's risk management framework and was not verifiable or reasonably auditable. On that basis, PB considered that the risk assessment was not rigorous and did not reasonably demonstrate the timing of expenditure proposed by Energex.[1388]

PB noted that the proposed expenditure represents a significant increase from past expenditure, and expressed concern that Energex had not demonstrated how the property development strategy would be delivered, particularly in relation to the first two years of proposed expenditure.[1389]

PB reviewed the proposed expenditure relating to the replacement of the warehousing and logistics site, the largest single project proposed, and noted a number of concerns with the risk assessment and options analysis underpinning the project.[1390] PB considered the process employed by Energex in relation to the proposed replacement of the warehousing site was not prudent considering the large expenditures involved, and instead recommended an allowance for upgrading the warehousing site over a ten year period as prudent and efficient expenditure.[1391] PB based its estimated costs for refurbishment of the warehousing site on advice prepared for Energex by Davis Langdon Australia Pty Ltd.[1392]

On the basis of its review, PB found that Energex's land and buildings capex had not been demonstrated to be prudent and efficient, and recommended expenditure in line with Energex's business as usual costs plus an allowance to refurbish the warehousing facility. PB further recommended that the level of business as usual costs be determined by removing the major building project expenditures found to be not prudent and efficient from the capex proposal. PB recommended a prudent and efficient level of land and buildings expenditure for Energex of $140 million over the next regulatory control period, representing a reduction of $158 million from

[1386] PB, *Report – Energex*, October 2009, p. 64.
[1387] PB, *Report – Energex*, October 2009, p. 67.
[1388] PB, *Report – Energex*, October 2009, p. 67.
[1389] PB, *Report – Energex*, October 2009, p. 68.
[1390] PB, *Report – Energex*, October 2009, p. 66.
[1391] PB, *Report – Energex*, October 2009, pp. 68–69.
[1392] Davis Langdon, *[Warehousing] Depot – Assessment of Cost for General Renewal*, November 2007.

Energex's capex proposal.[1393] This includes an allowance of $13 million for refurbishment of the warehousing facility.[1394]

Tools and equipment

PB undertook a high level review of Energex's proposed expenditure on tools and equipment.

As part of its review, PB considered the processes and procedures used to determine current and projected tooling and equipment levels. PB noted that the proposed tools and equipment expenditure is based on a business as usual approach, with Energex using a database to manage its tools and equipment that computes predicted usage levels based on historical levels of usage.[1395]

PB noted that the proposed decrease in tools and equipment expenditure is driven by a flat workforce growth forecast, efficiency improvements in the use of plant and equipment across the business, and the significant purchase of long life items in the current regulatory control period that will not require replacement in the next regulatory control period.[1396]

On the basis of its review, PB concluded that the proposed tools and equipment capex is prudent and efficient, and recommended that the tools and equipment capex proposed by Energex be accepted without adjustment.[1397]

AER considerations

The AER reviewed Energex's non–system capex proposal, taking into account additional information provided in support of the regulatory proposal and the advice of PB.

The AER notes PB's findings that the proposed expenditures for tools and equipment, motor vehicles and end–use computing assets are considered to be prudent and efficient.[1398] The AER notes that expenditures in these categories are either below or consistent with historical levels of expenditure.[1399] Having reviewed Energex's regulatory proposal and the policies and procedures underpinning these expenditures, the AER considers that the proposed expenditures for tools and equipment, motor vehicles and end–use computing assets represent the efficient costs of a prudent operator in Energex's circumstances.

Energex's proposed capex for non–system land and buildings is $298 million during the next regulatory control period, a significant increase of 128 per cent from the current regulatory control period.[1400]

[1393] PB, *Report – Energex*, October 2009, pp. 69–70.
[1394] PB, *Report – Energex*, October 2009, p. 69.
[1395] PB, *Report – Energex*, October 2009, p. 73.
[1396] PB, *Report – Energex*, October 2009, p. 74.
[1397] PB, *Report – Energex*, October 2009, p. 74.
[1398] PB, *Report – Energex*, October 2009, pp. 74–75.
[1399] Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
[1400] Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.

The AER notes that business case documentation or other supporting documentation for the high value individual property projects proposed by Energex was not available. This included documentation for expenditure proposed for the first year of the regulatory control period, as Energex intended to develop such documentation closer to project realisation.[1401] The AER notes that this approach to investment planning and approval differs from Energex's usual practice in relation to system capex, where Energex has prepared business cases to justify the proposed expenditure.[1402]

The AER notes PB's finding that the risk assessment used by Energex to prioritise building projects did not use Energex's risk management framework and was not verifiable or reasonably auditable. On that basis, PB considered that the risk assessment was not rigorous and did not reasonably demonstrate the timing of expenditure proposed by Energex.[1403]

In assessing the proposed land and buildings capex, PB specifically reviewed the proposed expenditure relating to the replacement of the warehousing site, the largest single project proposed, and identified a number of concerns with the risk assessment and options analysis underpinning the project.[1404] The AER notes PB's view that, given the subjective nature of the risk assessment and in the absence of a full site options analysis, the process employed by Energex in relation to the proposed replacement of the warehousing site has not been demonstrated to be prudent considering the large expenditures involved.[1405]

The AER considers that the requirement to replace the warehousing facility in the next regulatory control period has not been sufficiently established by Energex, particularly noting the recommendation of Maunsell Australia that the site will become untenable only in the medium to long term.[1406] The AER therefore considers that an allowance for upgrading the warehousing site over a ten year period is more representative of a prudent and efficient level of expenditure in the next regulatory control period.

On the basis of its review and advice from PB, the AER considers that the major building project expenditures proposed by Energex, which are not supported by business case documentation and contribute to a significant increase in expenditure from the current regulatory control period, have not been demonstrated to be prudent and efficient and should be removed from the capex proposal. The AER considers that Energex's land and buildings capex should align with Energex's business as usual costs (that is, excluding the proposed new major building projects) plus an allowance to refurbish the warehousing facility. The AER requested Energex model the impact of the AER's decision on non–system land and buildings capex. Energex advised that the adjustment to forecast non–system capex is $158 million.[1407]

[1401] PB, *Report – Energex*, October 2009, p. 67.
[1402] PB, *Report – Energex*, October 2009, p. 65.
[1403] PB, *Report – Energex*, October 2009, p. 67.
[1404] PB, *Report – Energex*, October 2009, p. 66.
[1405] PB, *Report – Energex*, October 2009, pp. 68–69.
[1406] Maunsell, *Distribution Facility Opportunities and Constraints Analysis*, May 2008, p. 47.
[1407] Energex, response to the AER, 11 November 2009.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's proposed non–system capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed non–system capex by $158 million[1408] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

F.5.4.6 Indirect costs

This section examines whether Energex's indirect costs, commonly referred to as overheads, are appropriate and are allocated in a manner that is likely to result in prudent and efficient investment for the delivery of standard control services. The AER considers that assessing indirect costs in this manner is relevant for determining whether the AER is satisfied that Energex's forecast capex reasonably reflects the capex criteria.

Energex proposal

Energex stated that indirect costs are costs that are required to run its business but which are not directly attributed to a specific activity or service. As a result, they are allocated across services consistent with previous practice and the AER approved cost allocation method.[1409]

Energex indicated that its indirect costs include:

- corporate support costs including the CEO, Executive Management, Finance, Regulatory Management, Human Resources, Legal and Business Support Services
- customer services including business support services, customer advocacy, government relations and energy market services
- environmental, safety management, regulatory and legal compliance
- information and communication technology (ICT)
- regulatory and legal compliance
- training, occupancy, leasing and communications and community activities.[1410]

Energex indicated that the most material contributor to its indirect costs is the provision of ICT services provided by SPARQ, which is jointly owned by Energex and Ergon Energy and provides ICT services to both businesses.[1411] Energex proposed ICT costs for the next regulatory control period of $457 million.[1412]

1408 See table F.14 for the treatment of the indirect cost component of this deduction.
1409 Energex, *Regulatory proposal*, July 2009, p. 188.
1410 Energex, *Regulatory proposal*, July 2009, p. 188.
1411 Energex, *Regulatory proposal*, July 2009, p. 189.
1412 Energex, *Regulatory proposal*, July 2009, p. 190.

Energex stated that as a distribution–only network business, the majority of its indirect costs are allocated to standard control services and that this limited comparisons with other network businesses that have an associated business (either retail business or gas network business).[1413]

Energex commissioned KPMG to perform a review of the prudency and efficiency of the ICT services delivered by SPARQ. KPMG found SPARQ to be an efficient ICT service provider, outperforming its peers in many of the efficiency indicators. Energex noted that this benchmarking exercise is performed and reviewed annually by the SPARQ Board and the Energex Board.[1414] KPMG also concluded that a reasonable process was followed to develop the Joint ICT Plan, that the initiatives in the plan aligned to business needs and broader industry direction and that the resulting regulatory forecasts were prudent.[1415]

Energex identified the following key drivers of the development of the ICT capital program:

- ensure Energex's ICT capability supports critical and operational business processes and activities through a regular cycle of system upgrades and replacement
- achieve continuous improvement through managing system changes by facilitating business improvements identified over the course of the year
- target strategic initiatives that would enhance and improve ENERGEX's business capability
- provide and promote ICT investment decisions that assist business alignment initiatives between ENERGEX and Ergon Energy that lead to improved business efficiency.[1416]

Consultant review

PB noted that Energex allocates indirect costs as per the AER's approved cost allocation methodology, which results in 77 per cent of indirect costs being allocated to capex and 23 per cent being allocated to opex.[1417]

In its review of Energex's proposed capex, PB found that Energex has allocated a total of $1870 million in indirect costs to capex for the next regulatory control period.[1418]

PB indicated that it assessed the prudence and efficiency of indirect costs as part of its review of capex and opex at an expenditure category level. For all but two categories of expenditure, PB found that there were no significant step changes. However, for

[1413] Energex, *Regulatory proposal*, July 2009, p. 188.
[1414] Energex, *Regulatory proposal*, July 2009, p. 189.
[1415] Energex, *Regulatory proposal*, July 2009, p. 189.
[1416] Energex, *Regulatory proposal*, July 2009, p. 190.
[1417] PB, *Report – Energex*, September 2009, p. 14.
[1418] PB, *Report – Energex*, September 2009, p. 13.

property and ICT, PB identified step changes in expenditure relative to current levels. As a result, PB requested additional information on the drivers behind the increase in these two areas.[1419]

In relation to property indirect costs, PB noted that expenditure was proposed to increase by 23 per cent in 2010–11 and 14 per cent in 2011–12. PB noted Energex's comment that the main driver for the increase was due to government surcharges for land tax on existing properties. PB considered that in the absence of these surcharges, Energex's proposed property indirect costs would be similar to current levels. On this basis, PB considered the expenditure to be reasonable.[1420]

PB also noted a proposed increase in ICT indirect costs, of 16 per cent in 2010–11 and 18 per cent in 2011–12.[1421] PB noted that the bulk of Energex's ICT services are delivered by SPARQ and covered by a service charge to Energex which it recognises as an opex related charge.[1422]

In order to establish the underlying prudence and efficiency of the proposed forecast ICT expenditure, PB reviewed the ICT capex proposed by both Energex and SPARQ (as it relates to Energex) and considered these as if they were one proposal.[1423]

After reviewing Energex's regulatory proposal and supporting documentation, PB requested further information from Energex and SPARQ to demonstrate the prudence and efficiency of the proposed ICT program.[1424] PB conducted a detailed review of this material in order to substantiate the proposed expenditure through demonstration of business cases and in the context of historical data.[1425]

PB noted that, of the $197 million of ICT expenditure proposed by Energex and SPARQ, $168 million was 'steady state', or business as usual, expenditure and $29 million was for new capability. More than half ($15.5 million) of new capability expenditure was for a single project, 'DMS Stage 2'.[1426]

In assessing the proposed ICT expenditure, PB focused on proposed new capabilities, having regard to:[1427]

- strategic alignment of individual ICT projects or programs with Energex's broader strategies, policies or other objectives and drivers
- project need, materiality and timing
- options analysis, including explanation as to why the preferred option is the most efficient

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[1419] PB, *Report – Energex*, September 2009, p. 14.
[1420] PB, *Report – Energex*, September 2009, p. 15.
[1421] PB, *Report – Energex*, September 2009, p. 14.
[1422] PB, *Report – Energex*, September 2009, p. 55.
[1423] PB, *Report – Energex*, September 2009, p. 55.
[1424] PB, *Report – Energex*, September 2009, p. 58.
[1425] PB, *Report – Energex*, September 2009, pp. 58–62.
[1426] PB, *Report – Energex*, September 2009, pp. 58–59.
[1427] PB, *Report – Energex*, September 2009, p. 60.

- financial and/or economic appraisal that demonstrates value for money, cost savings and/or net benefits of the project or program
- procurement and delivery strategy.

In relation to ICT capex proposed by SPARQ, PB found that the majority of projects had a clear description of need and purpose, but that expenditures were not supported by analysis that demonstrated prudence or efficiency.[1428] One exception to this was for the DMS Stage 2 project, for which PB found the business case to be comprehensive, with the need and net benefits of the project being clearly demonstrated, including a financial appraisal, quantification of efficiency gains, and cost savings associated with implementing the project based on staffing numbers.[1429] PB also found a lack of consistency in the development of business cases for major projects. For these reasons, PB concluded that Energex had not demonstrated that the proposed ICT expenditure by SPARQ for new capability is prudent or efficient.[1430]

In relation to ICT expenditure proposed by Energex, PB noted a significant overall reduction in expenditure in the next regulatory control period and stated that this was appropriate given that the majority of assets owned by Energex have gradually been transferred to SPARQ.[1431]

PB concluded that, with the exception of DMS Stage 2 expenditure, the proposed expenditure associated with the new capability initiatives capitalised within SPARQ has not been shown to be prudent or efficient and recommends a business as usual ICT expenditure forecast.[1432]

To calculate the reduction in the service charge associated with SPARQ capex, PB used the 2008–09 SPARQ service charge as the base year cost and assumed the increase in the ICT indirect cost during the next regulatory control period is predominately driven by SPARQ capex. PB then applied a reduction to the increases in the SPARQ service charge that is proportional to the reduction recommended for the SPARQ ICT capex. These steps are presented in table F.13.

PB estimated that its recommended $9.5 million ($2009–10) reduction in ICT indirect costs results in a $7.3 million reduction in capex and a $2.2 million reduction in opex over the regulatory control period.[1433]

1428 PB, *Report – Energex*, September 2009, p. 61.
1429 PB, *Report – Energex*, September 2009, p. 61.
1430 PB, *Report – Energex*, September 2009, p. 62.
1431 PB, *Report – Energex*, September 2009, p. 62.
1432 PB, *Report – Energex*, September 2009, p. 62.
1433 PB, *Report – Energex*, September 2009, p. xvi.

Table F.13: **PB recommended reduction in ICT indirect costs expenditure – SPARQ ($m, 2009–10)**

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ICT indirect costs	81.4	95.9	102.5	100.3	98.4	478.5
ICT baseline costs (2009–10)	70.1	70.1	70.1	70.1	70.1	350.5
Increase in ICT ($m)	11.3	25.8	32.4	30.2	28.3	128.0
% reduction in SPARQ capex recommended by PB	–5.7	– 9.4	– 6.9	– 6.1	– 8.1	– 7.2
Proportional reduction in ICT indirect cost	– 0.6	– 2.4	– 2.3	– 1.8	– 2.3	– 9.5
Reduction in capex indirect cost	–0.5	–1.8	–1.8	–1.4	–1.8	– 7.3
Reduction in opex indirect cost	–0.1	–0.6	–0.5	–0.4	–0.5	–2.2
PB recommendation	80.8	93.5	100.2	98.5	96.1	469.0

Source: PB, *Report – Energex*, September 2009, p. 17.
Note Reductions in indirect costs allocated to capex and opex based on the 77:23 allocation of indirect costs to capex and opex that result from Energex's cost allocation methodology. Totals may not add due to rounding.

AER considerations

The AER notes that PB has assessed the prudence and efficiency of indirect costs as part of its review of capex (and opex) at an expenditure category level and found that for all but two categories of indirect costs, there were no significant step changes in expenditure.

In relation to property indirect costs, the AER notes that the main reason for the step change is due to government surcharges for land tax on existing properties. The AER considers that these costs are outside Energex's control and therefore considers them to be acceptable. The AER notes PB's finding that, in the absence of government surcharges for land tax on existing properties, Energex's proposed property indirect costs would be similar to current levels. The AER therefore considers Energex's property indirect costs are reasonable.

The AER notes the proposed step change in ICT indirect costs in the next regulatory control period. The AER notes that the bulk of Energex's ICT is delivered by SPARQ and covered by a service charge to Energex. The AER considers that PB's review of SPARQ's ICT capex is an appropriate method of determining the prudence and efficiency of SPARQ's service charges to Energex.

The AER notes that the majority of ICT expenditure proposed by SPARQ is for a business as usual level of capability. The AER considers that PB's focus on expenditure for new capabilities is appropriate. This is because the annual reviews of

ICT expenditure undertaken by Energex is likely to have better established the efficiency and prudency of business as usual expenditure compared to expenditure for new capabilities.

The AER notes that PB has conducted a detailed review of the proposed new capabilities, having had regard to a range of considerations, including project need and efficiency, options analysis and delivery strategy. As a result, the AER accepts PB's finding that expenditure proposed for the DMS Stage 2 project is well justified, as it is based on a comprehensive business case.

Regarding other projects for new capability, the AER notes PB's findings of a lack of consistency in the development of business cases for major projects. The AER also notes PB's finding that expenditure proposed for other new capability projects is not supported by analysis that demonstrated prudence or efficiency. For these reasons, the AER accepts PB's conclusion that Energex has not demonstrated that the proposed ICT expenditure by SPARQ for new capability projects (except for DMS Stage 2) is prudent or efficient. The AER requested that Energex model the impact of the AER's decision on indirect costs. Energex advised that the adjustment to indirect costs allocated to capex is a reduction of $7 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal and PB's report, the AER is not satisfied that Energex's forecast of indirect costs reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed allocation of indirect costs to capex by $7 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

F.5.5 Deliverability of the forecast capex program

This section examines the methods proposed by Energex to deliver its proposed capex program within the next regulatory control period in the context of determining whether the AER is satisfied that Energex's forecast capex reasonably reflects the capex criteria.

Energex regulatory proposal

Energex stated that its performance over the current regulatory control period demonstrates its ability to deliver record capex and opex programs. Energex attributes its delivery performance to the integration of strategies for managing its people, contracts, procurement and design.[1434]

Energex stated that the delivery of its works program in the next regulatory control period would depend heavily on the continuation of its current multi-faceted approach, which Energex intends to consolidate and refine.[1435]

In relation to staffing, Energex stated that its current internal workforce, which includes significantly more tradespersons than in 2004, will be able to deliver the

[1434] Energex, *Regulatory proposal*, July 2009, p. 210.
[1435] Energex, *Regulatory proposal*, July 2009, p. 210.

forecast work program with support from appropriate contract resources and supplementary processes. Energex has developed a *People Strategy for 2010–15* that is aimed at retaining and developing staff through a range of specific programs, including for tradesperson recruitment, apprentices, para-professional traineeships, graduates and technical skills.[1436]

Regarding contracting, Energex sought advice from KMPG in revising its contracting strategy to:[1437]

- build on the strengths of the current arrangements through consolidation of the supplier base and resultant long term efficiencies
- focus on skills gaps and future resource needs
- target 'on-time and to standard' contracting services
- align service contract performance to Energex's business objectives.

Energex indicated that it applies its strategic procurement method to materials and services contracts and stated that this resulted in the best market value. Energex also indicated its intention to include a pre-qualification step in its procurement process to streamline the engagement of reliable resource providers.[1438]

Consultant review

PB reviewed Energex's ability to deliver its proposed works program during the next regulatory control period.[1439]

PB noted that because Energex's internal staffing levels are forecast to remain relatively constant over the next regulatory control period, the increased work load will have to be addressed by a combination of strategies, such as outsourcing and use of standardised designs. PB also stated that Energex will have to ensure delivery of materials necessary to construct the proposed capital works.[1440]

To form a view on Energex's ability to deliver its proposed work programs, PB reviewed:[1441]

- Energex's delivery performance during the current regulatory control period
- the strategies Energex has put in place to continue to increase its service delivery capability.

PB found that the contracting strategies Energex has implemented indicate that it can develop the capability to deliver the proposed operating and capital works programs during the next regulatory control period.[1442]

1436 Energex, *Regulatory proposal*, July 2009, p. 211.
1437 Energex, *Regulatory proposal*, July 2009, p. 212.
1438 Energex, *Regulatory proposal*, July 2009, p. 213.
1439 PB, *Report – Energex*, October 2009, pp. 122–126.
1440 PB, *Report – Energex*, October 2009, p. 122.
1441 PB, *Report – Energex*, October 2009, p. 123.

PB also considered that a move by Energex to prequalification schemes will result in additional contracting efficiencies and facilitates more effective contractor management.[1443]

In addition, PB considered that the material procurement practices Energex uses, particularly materials with long lead times, should ensure that materials are available when required and that unavailable materials should not result in delays to the delivery and subsequent commissioning of proposed projects.[1444] PB also considered that Energex's ability to procure additional resources is strengthened in light of the recent global financial crisis and the subsequent increased availability of resources in comparison with the current regulatory control period.[1445]

On the basis of the above findings, PB concluded that Energex should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.[1446]

AER considerations

The AER notes that Energex's forecast capex program represents a significant increase compared to the level of investment undertaken in the current regulatory control period. The AER considers that Energex appears to be well prepared for delivering this increased level of works. A key reason for this is that Energex has demonstrated its ability to significantly expand its work program during the current regulatory control period, with system capex and opex expected to increase by 59 per cent between 2005–06 and 2009–10, from \$0.8 billion to an estimated \$1.3 billion.[1447] This increase compares to a forecast increase in system capex and opex of only 29 per cent between 2010–11 and 2014–15, from \$1.3 billion to \$1.6 billion.[1448]

The AER notes PB's findings (discussed in detail in chapter 7) that Energex's overall approach to planning and implementing its capex program is consistent with good industry practice. The AER considers that this has, and will continue, to underpin Energex's ability to deliver an increasing level of works. Further, the AER considers that the range of enhancements being made by Energex in relation to its delivery processes, particularly in the areas of contracting and procurement, should improve Energex's ability to deliver its future works program.

The AER notes PB's conclusions that Energex should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

Having considered Energex's forecast capex program and proposed delivery strategies, and the advice of PB, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability.

[1442] PB, *Report – Energex*, October 2009, p. 126.
[1443] PB, *Report – Energex*, October 2009, p. 126.
[1444] PB, *Report – Energex*, October 2009, p. 126.
[1445] PB, *Report – Energex*, October 2009, p. 125.
[1446] PB, *Report – Energex*, October 2009, p. 126.
[1447] PB, *Report – Energex*, October 2009, p. 123.
[1448] PB, *Report – Energex*, October 2009, p. 122.

The AER is also satisfied that the deliverability of Energex's forecast capex is consistent with the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

The AER notes that the deductions it has proposed for Energex's forecast capex in this draft decision provides further confidence that Energex will be able to deliver its program of works.

F.6 AER conclusion

The AER has reviewed Energex's proposed forecast capex allowance and, for the reasons set out in this appendix, the AER is not satisfied that the proposed forecast capex allowance reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER. In particular the AER considers:

- Energex's proposed growth capex does not reflect a realistic expectation of the demand forecast required to achieve the capex objectives

- Energex's proposed non–system capex on major building projects has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the capex criteria

- indirect costs associated with the ICT services do not reasonably reflect the capex criteria, including the capex objectives

- the expenditures associated with Energex's application of its input cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.

As the AER is not satisfied that the total capex allowance reasonably reflects the capex criteria, under clause 6.5.7(d) of the NER the AER must not accept the forecast capex proposed by Energex. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the capex for Energex over the next regulatory control period which it is satisfied reasonably reflects the capex criteria, taking into account the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capex for Energex is $5718 million ($2009–10), as set out in table F.14.

Table F.14: AER conclusion on Energex's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
Adjustment to growth capex	–37.3	–43.8	–60.5	–66.9	–80.0	–288.6
Adjustment to non–system capex	–105.0	–32.7	–20.6	0.0	0.0	–158.3
Adjustment to indirect costs	–0.5	–1.7	–1.6	–1.3	–1.7	–6.8
Re-inclusion of indirect costs removed in the adjustments to growth and non–system capex	19.7	14.3	15.7	12.8	15.1	77.7
Adjustment to cost escalators	–51.6	–61.2	–75.6	–85.1	–98.2	–371.7
AER capex allowance	1064.8	1144.6	1159.3	1151.9	1197.7	5718.3

Notes: Totals may not add due to rounding.
The indirect costs included in adjustments to growth and non–system capex are not to be removed from Energex's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Energex's indirect costs, as discussed in section 7.8.4.

G. Ergon Energy forecast capital expenditure

G.1 Introduction

This introduction is to be read in conjunction with chapter 7 of this draft decision. It sets out the AER's detailed considerations and conclusions on Ergon Energy's proposed capex allowance for the next regulatory control period. The regulatory requirements and the general approach used by the AER to assess Ergon Energy's capex proposal is set out in chapter 7 of this draft decision. This appendix includes:

- an overview of Ergon Energy's capex proposal
- specific comments on the capex proposal from stakeholders
- the review and findings of the AER's consultant, PB
- the issues and the AER's reasoning and considerations, including a discussion of proposed capex by category
- the AER's conclusions on, and estimate of, Ergon Energy's forecast capex allowance for the next regulatory control period that it is reasonably satisfied reflects the capex criteria, having regard to the capex factors.

G.2 Ergon Energy regulatory proposal

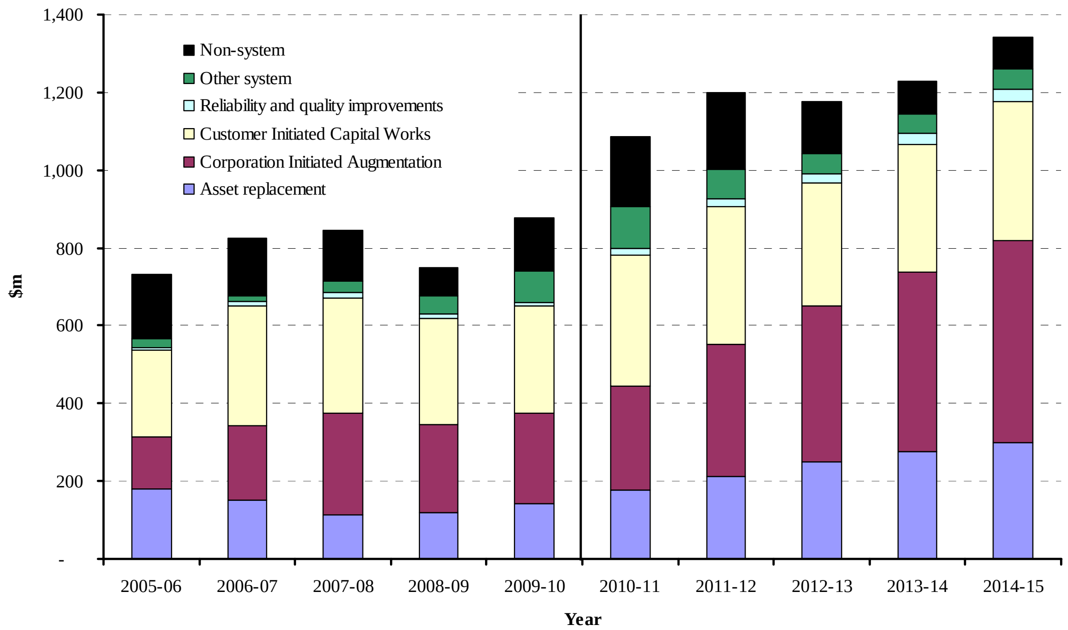
Ergon Energy proposed capex of $6033 million ($2009–10) for the next regulatory control period. Table G.1 shows the annual profile of Ergon Energy's capex proposal by driver. Figure G.1 compares Ergon Energy's forecast capex with actual expenditure incurred in the current regulatory control period.

Table G.1: Ergon Energy proposed capex by driver ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement	177.4	212.7	250.0	274.8	299.2	1214.1
Corporation initiated augmentation (growth capex)	267.8	339.4	401.3	463.6	518.9	1990.9
Customer initiated capital works (growth capex)	336.1	355.0	315.6	328.7	359.6	1695.0
Reliability and quality improvements	18.3	20.9	24.5	28.3	30.4	122.4
Other system capex	105.6	72.9	50.8	50.4	51.7	331.4
Non–system capex	180.9	199.0	135.2	82.3	81.7	679.1
Total capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 192.
Note: Totals may not add due to rounding.

Figure G.1: Ergon Energy's actual and proposed capex by driver ($m, 2009–10)



Source: Ergon Energy, *Regulatory Proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

Ergon Energy forecast capex for the next regulatory control period that is approximately 50 per cent (in real terms) higher than what it expects to spend in the current regulatory control period. Ergon Energy's increased capex requirement is mainly driven by asset replacement, corporation initiated augmentation, and customer initiated capital works, reliability and quality improvements.

Ergon Energy proposed growth capex of $3686 million ($2009–10), which represents 61 per cent of total forecast capex. Ergon Energy's growth capex is forecast to increase by approximately 52 per cent (in real terms) from the current regulatory control period.[1449] Total growth capex includes:

- corporation initiated augmentation work (CIA) – 54 per cent of forecast growth capex is accounted for by corporation initiated augmentation work. This is forecast to increase by 90 per cent (in real terms) compared to expenditure in the current regulatory control period. Ergon Energy indicated this category of expenditure is for building additional network capacity that will meet demand growth and address forecast system constraints[1450]

- customer initiated capital work (CICW) – 46 per cent of forecast growth capex is accounted for by customer initiated capital works, which is forecast to increase by 23 per cent (in real terms) compared to expenditure in the current regulatory

[1449] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
[1450] Ergon Energy, *Regulatory proposal*, July 2009, p. 203.

control period. Ergon Energy indicated that this category of expenditure is for undertaking forecast levels of customer connections work.[1451]

Ergon Energy proposed $1214 million ($2009–10) in asset replacement expenditure, which represents an increase of 72 per cent (in real terms) compared to the current regulatory control period. It accounts for 20 percent of the forecast capex program. Ergon Energy indicated that this category includes expenditure relating to defects as well as condition based replacements and refurbishments.[1452]

Ergon Energy proposed $122 million ($2009–10) in reliability and quality improvement capex, which is an increase of 131 per cent (in real terms) compared to expenditure during the current regulatory control period. Ergon Energy noted that the expenditure is required to meet the minimum service standard requirements under the Electricity Industry Code and to address the performance of the worst performing feeders.[1453]

Ergon Energy proposed $331 million ($2009–10) in other system capex, which represents an increase of 75 per cent (in real terms) compared to the current regulatory control period. This expenditure relates to a number of projects and programs, including:[1454]

- the UbiNet project
- retrofitting auto-reclose and sensitive earth fault protection on existing feeders
- single wire earth return (SWER) augmentation work
- undergrounding
- other programs, which comprise low voltage fuse retrofits, low voltage spreaders, substation security, oil containment bunding and alternate substation AC supplies.

Ergon Energy forecast $679 million ($2009–10) in non–system capex. This is an increase of approximately 4 per cent (in real terms) compared to the current regulatory control period. Ergon Energy attributed this expenditure to the purchase of necessary tools and equipments, information, communications and technology (ICT) systems upgrades and replacement, increased number of motor vehicles due to substantial growth in the system and customer work programs, and the need to bring property assets to an acceptable standard.[1455]

Ergon Energy developed the capex forecasts using 2007–08 as the base year, except for office equipment and furniture expenditure, where only part of the 2007–08 base

[1451] Ergon Energy, *Regulatory proposal*, July 2009, p. 206.
[1452] Ergon Energy, *Regulatory proposal*, July 2009, p. 196.
[1453] Ergon Energy, *Regulatory proposal*, July 2009, p. 211.
[1454] Ergon Energy, *Regulatory proposal*, July 2009, pp. 219–221.
[1455] Ergon Energy, *Regulatory proposal*, July 2009, pp. 222–235.

year that relates to existing buildings is used to prepare the forecasts. Capex real cost escalators have been applied to all of Ergon Energy's asset categories.[1456]

Ergon Energy stated that the forecasts presented in its capex forecast only relate to standard control services and include direct cost and shared costs (overheads). Ergon Energy stated its capex forecasts are based on the plans, policies, procedures and strategies which promote the achievement of the capex objectives. Ergon Energy also stated that it applied a combination of robust bottom up or top down approaches to translate the plans, policies, procedures and strategies into capex forecasts for the next regulatory control period.[1457]

G.3 Submissions

The AER received three submissions relating specifically to Ergon Energy's proposed capex for the next regulatory control period, from the Energy Users Association of Australia (EUAA), Queensland Council of Social Service (QCOSS) and SPA Consulting Engineers (SPA).

EUAA and QCOSS sought assurances that the capex proposed by Ergon Energy is efficient[1458] and that Ergon Energy's demand management activities are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[1459]

The EUAA also noted the very significant expansion of expenditure by Ergon Energy on corporate property and stated that the AER should investigate this carefully to determine its purpose, relevance and benefit.[1460]

SPA stated that the distribution networks should be constructed economically to deliver reliability standards demanded by the community.[1461]

G.4 Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of Ergon Energy's proposed expenditure.[1462]

Based on its review, PB found $4355 million (81 per cent) of the proposed system capex to be prudent and efficient. PB's key findings are as follows:[1463]

- Ergon Energy's capital governance is generally consistent with good electricity industry practice

[1456] Ergon Energy, *Regulatory proposal*, July 2009, p. 253.
[1457] Ergon Energy, *Regulatory proposal*, July 2009, p. 247.
[1458] EUAA, *Submission to the AER*, August 2009, p. 20; and QCOSS, *Submission to the AER*, August 2009, p. 2.
[1459] EUAA, *Submission to the AER*, August 2009, pp. 20–21; and QCOSS, *Submission to the AER*, August 2009, pp. 3–4.
[1460] EUAA, *Submission to the AER*, August 2009, p. 21.
[1461] SPA, *Submission to the AER*, August 2009, p. 2.
[1462] PB, *Report – Ergon Energy*, October 2009, p. 1.
[1463] PB, *Report – Ergon Energy*, October 2009, pp. xii–xiii.

- the options analysis included in Ergon Energy's business case documentation lacked robustness, generally did not consider non–network alternatives, and included only limited NPV analysis to demonstrate the efficiency of the selected option

- the planning criteria used by Ergon Energy are aligned with good electricity industry practice, however, demand forecast application is only partially demonstrated and non–network alternatives are not generally considered

- asset replacement policies and procedures are in line with good electricity industry practice, however, asset replacement practices are not consistently implemented

- reliability and quality improvement planning follows many of the elements of good electricity industry practice

- an adjustment in expenditure is recommended in the following categories for the reasons outlined:

  - a reduction of $526 million to the corporation initiated augmentation growth capex forecast as a result of deferring this expenditure for 18 months, based on MMA advice that Ergon Energy's maximum demand forecasts were too high

  - a reduction of $318 million to customer initiated capital works growth capex forecast as PB is of the view that the forecast has not been sufficiently substantiated

  - a reduction of $119 million to the asset replacement capex forecast as PB's view is that the volume forecasts underpinning the forecasts were not demonstrated to be prudent

  - a reduction in reliability and quality improvement capex of $35 million, as the increase above business as usual level for the feeder improvement program has not been demonstrated to be prudent and efficient.

PB recommended that system capex for the next regulatory control period should be reduced by $999 million (19 per cent) from the level proposed by Ergon Energy.[1464] Table G.2 presents the system capex recommended by PB.

[1464] PB, *Report – Ergon Energy*, October 2009, p. xiii.

Table G.2: PB recommended system capex allowance for Ergon Energy ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	905.3	1000.9	1042.1	1145.8	1259.8	5353.9
PB adjustments to system capex						
Corporation initiated augmentation growth	–93.3	–100.5	–101.4	–114.8	–116.4	–526.4
Customer initiated capital works	–61.8	–79.1	–39.8	–53.4	–84.0	–318.1
Asset replacement	–9.8	–19.3	–31.0	–30.0	–28.7	–118.8
Reliability and quality improvement	–2.6	–4.5	–7.1	–9.8	–11.4	–35.4
PB recommendation	737.8	797.5	862.8	937.8	1019.3	4355.2

Source: PB, *Report – Ergon Energy*, October 2009, pp. xiii, 41, 55, 62.
Note: Totals may not add due to rounding.

For non–system capex, PB found Ergon Energy's proposed level of expenditure not to be prudent and efficient, and has recommended reductions as follows:[1465]

- a reduction of $65 million to the proposed ICT capex to reflect removal of costs associated with the change program, for which no information was provided to demonstrate prudence or efficiency
- a reduction of $191 million to the proposed property capex which reflects a business as usual approach. In the view of PB, the need and timing for the proposed building program is only partially demonstrated and, in general, alternatives have not been well considered.

PB found that Ergon Engery's proposed capex for fleet and tools and equipment is prudent and efficient.[1466]

PB recommended that Ergon Energy's proposed non–system capex allowance for the next regulatory control period should be reduced by $256 million from the levels proposed by Ergon Energy. Table G.3 presents PB's recommended non–system capex.[1467]

[1465] PB, *Report – Ergon Energy*, October 2009, pp. xiii–xiv.
[1466] PB, *Report – Ergon Energy*, October 2009, p. xiv.
[1467] PB, *Report – Ergon Energy*, October 2009, p. xiv.

Table G.3: PB's recommended non–system capex allowance for Ergon Energy ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	180.9	199.0	135.2	82.3	81.7	679.1
Less PB adjustment to non–system capex						
ICT	–13.1	–13.1	–13.1	–13.1	–12.8	–65.2
Property	–83.0	–103.0	–37.9	14.3	18.8	–190.8
PB recommendation	84.8	82.9	84.1	83.4	87.8	423.0

Source: PB, *Report – Ergon Energy*, October 2009, pp. xiv, 81, 88.

PB's specific findings on each area of Ergon Energy's capex proposal are described in section G.5.4 of this appendix.

G.5 Issues and AER considerations

This section presents the AER's consideration of the following aspects of Ergon Energy's regulatory proposal:

- its policies, procedures and methods
- its cost estimation processes
- the application of input cost escalators
- proposed expenditure by major category
- the deliverability of the forecast capex program.

G.5.1 Policies, procedures and methods

This section examines whether Ergon Energy's capex planning practices are appropriate and provide a framework that is likely to result in prudent and efficient investment decisions. The AER considers that assessing these practices in this manner is relevant for determining whether the AER is satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria.

Ergon Energy regulatory proposal

Ergon Energy's framework for capex planning activities is described through its asset management plan. Ergon Energy stated that the asset management plan provides a framework for the efficient management of its electricity infrastructure assets over their life cycle, balancing costs against service obligations and stakeholder expectations. The asset management plan describes:[1468]

[1468] Ergon Energy, *Regulatory proposal*, July 2009, p. 134.

- the role of Ergon Energy's corporate visions, strategies and management practices in guiding its approach to asset management

- the plans and programs established by Ergon Energy to deliver its asset augmentation, replacement and maintenance requirements, including Ergon Energy's major asset programs, the nature of its expenditure forecasts, and the systems, models and governance arrangements supporting asset management

- how Ergon Energy will deliver its approved program of works, including identifying the practices and processes supporting Ergon Energy's operations.

Ergon Energy stated that its capex forecasting methodology uses a combination of bottom up and top down approaches to translate its plans, policies, procedures and strategies into capex forecasts for the next regulatory control period. Ergon Energy described the key elements of its capex forecasting process as being:[1469]

- consideration of current and historical network condition and performance

- assessment of the network risk profile and expenditure drivers, including internal operational factors as well as external factors such as regulatory obligations, service standards and demand forecasts

- refining and confirming the policies, strategies and procedures for management of the distribution system

- development of plans outlining the required capex program

- development of plans for delivery of the capex program

- reflection of capex program into internal models and systems.

The key documents which summarise Ergon Energy's capex plans are the sub–transmission network augmentation plans and distribution network augmentation plans for each of Ergon Energy's six geographic regions, and the asset equipment plans which document the maintenance and replacement strategies for 26 asset equipment types.[1470]

Ergon Energy stated that it has a comprehensive framework for the development and prioritisation of its asset investment program, supported by a hierarchy of governance bodies and approval authorities.[1471] The key elements of Ergon Energy's governance and approval framework are:

[1469] Ergon Energy, *Regulatory proposal*, July 2009, pp. 150–151.
[1470] Ergon Energy, *Regulatory proposal*, July 2009, pp. 134–135.
[1471] Ergon Energy, *Regulatory proposal*, July 2009, p. 152.

- the Ergon Energy Board is accountable for the enterprise investment portfolio, and maintains the alignment of investments with Ergon Energy's strategic direction and performance outcomes[1472]

- the Investment Review Committee (IRC) supports the Ergon Energy Board and Chief Executive by developing and recommending a balanced capital (and operating) investment portfolio and providing a strategic oversight and scrutiny function[1473]

- the executive management team annually set specific portfolio performance metrics and milestones representing each portfolio's expected contribution to Ergon Energy's strategic development and key result target areas[1474]

- the Network Investment Review Committee, a sub–committee of the IRC, provides similar support to the General Manager Network as the IRC provides to the Chief Executive and Board, to facilitate the efficient and effective management of all network asset related capex in accordance with the asset management plan[1475]

- the Chief Financial Officer is delegated a role in investment management and prioritisation on behalf of the IRC in the non–network classes, customer service, change, growth and research and development areas.[1476]

Consultant review

PB reviewed Ergon Energy's capex planning and governance policies and procedures as a critical element of assessing the prudence and efficiency of the proposed capex for the next regulatory control period. Given the impracticality of individually assessing the reasonableness of each capital investment decision represented by Ergon Energy's proposal, PB reviewed the framework in which decisions are made to determine whether the relevant policies and procedures align with good electricity industry practice and the approach taken by Ergon Energy is likely to result in appropriate expenditure.[1477]

PB developed its view on Ergon Energy's policies and procedures through a desktop review of documentation, discussions with Ergon Energy's staff and as an integral part of its review of specific projects and programs of work. Reviewing policies and procedures in the context of specific proposed expenditures allowed PB to confirm appropriate application and implementation.[1478]

In relation to Ergon Energy's capex planning and governance policies and procedures, PB concluded that:

1472 Ergon Energy, *Regulatory proposal*, July 2009, p. 153.
1473 Ergon Energy, *Regulatory proposal*, July 2009, p. 153.
1474 Ergon Energy, *Regulatory proposal*, July 2009, p. 153.
1475 Ergon Energy, *Regulatory proposal*, July 2009, p. 154.
1476 Ergon Energy, *Regulatory proposal*, July 2009, p. 154.
1477 PB, *Report – Ergon Energy*, October 2009, p. 8.
1478 PB, *Report – Ergon Energy*, October 2009, p. 8.

- Ergon Energy's capitalisation policy supports a reasonable and pragmatic approach to classifying business expenditures, and is applied throughout the organisation in a consistent and accurate manner[1479]

- Ergon Energy is developing an extensive and well integrated capital governance framework which, although not yet fully implemented, was found to accord with the principles of good asset management, prudent business management, and good electricity industry practice in general[1480]

- Ergon Energy's planning criteria, while inherently conservative, are in accord with good electricity industry practice. The criteria are appropriately applied and suitable for the purposes of developing the relevant elements of the capex forecast[1481]

- the quality, completeness and robustness of Ergon Energy's options analysis varied considerably, such that while Ergon Energy's procedure is prudent in requiring options analysis to be conducted, the inconsistent and incomplete application of the process leads to results that do not clearly demonstrate efficient investment[1482]

- the prudent application of demand forecasts in the development of Ergon Energy's proposed capex investments was only partially demonstrated and evidenced by the business documentation[1483]

- in current practice, Ergon Energy rarely recognises efficient non–network alternatives as potential options when considering anticipated network constraints. However, Ergon Energy is developing its non–network alternative capability, and has pilot projects and trials in progress; which aligns broadly with good electricity industry practice[1484]

- Ergon Energy's key asset replacement policies and procedures generally accord with the principles of good asset management and good electricity industry practice, however asset replacement practices are not consistently implemented[1485]

- Ergon Energy's policies and procedures as they relate to the management of reliability and quality of supply improvement are generally in accord with good electricity industry practice.[1486]

[1479] PB, *Report – Ergon Energy*, October 2009, p. 22.
[1480] PB, *Report – Ergon Energy*, October 2009, pp. 28–29.
[1481] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1482] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1483] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1484] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1485] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1486] PB, *Report – Ergon Energy*, October 2009, p. 58.

AER considerations

The AER reviewed Ergon Energy's capex planning and governance framework, and sought advice from PB as to the appropriateness of the key plans, policies and procedures underpinning Ergon Energy's capex proposal. The AER did not receive any submissions that related specifically to Ergon Energy's capex planning and governance policies and procedures.

The AER notes that PB addressed specific issues regarding the formulation or application of Ergon Energy's capex planning and governance policies or procedures through its recommendations on the prudent and efficient level of expenditure for each capex component. As such, the AER's general conclusions in this section as to the appropriateness of Ergon Energy's capex planning and governance policies and procedures should be read in conjunction with the discussion on specific elements of Ergon Energy's capex proposal.

The AER reviewed Ergon Energy's capex governance framework, including documentation provided by Ergon Energy with respect to its capital budgeting, evaluation, approval, monitoring and review procedures, and delegation structures. The AER notes the central planning role of the IRC, and its sub-committee the Network Investment Review Committee, in developing and recommending Ergon Energy's capital investment plans in support of the designated approval authorities.[1487]

The AER notes PB's view that Ergon Energy is developing an integrated capital governance framework. The framework, when fully implemented, will accord with the principles of good asset management, prudent business management, and good electricity industry practice in general.[1488] The AER considers that this finding supports a view that Ergon Energy's capex governance framework, once fully implemented, will be robust and provide adequate assurance that investment decisions are likely to be prudent and efficient.

The AER notes PB's advice that Ergon Energy's planning criteria, while inherently conservative, are in accord with good electricity industry practice, are appropriately applied and suitable for the purposes of developing the relevant elements of the capex forecast.[1489] On this basis, the AER considers that Ergon Energy's capex planning processes are likely to appropriately identify investment needs. This view is supported by PB's finding that, where business case documentation was available, the need and timing for the proposed expenditure was clearly addressed. [1490]

However, the AER notes that the quality, completeness and robustness of Ergon Energy's options analysis was found by PB to vary considerably. As such the AER considers that while Ergon Energy's procedure is prudent in requiring options analysis to be conducted, the inconsistent and incomplete application of the process does not clearly demonstrate that investments are likely to be efficient. In this regard,

[1487] Ergon Energy, *Regulatory proposal*, July 2009, pp. 76–77
[1488] PB, *Report – Ergon Energy*, October 2009, pp. 28–29.
[1489] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1490] PB, *Report – Ergon Energy*, October 2009, p. 40.

the AER notes that Ergon Energy rarely recognises efficient non–network alternatives as potential options when considering anticipated network constraints.[1491]

The AER notes PB's view that Ergon Energy's key asset replacement policies and procedures generally accord with the principles of good asset management and good electricity industry practice, but that asset replacement practices are not consistently implemented.[1492]

Having considered Ergon Energy's capex planning and governance framework, and advice from PB, the AER is satisfied that Ergon Energy's policies and procedures for capex planning and governance generally support the view that their application is likely to lead to prudent and efficient investment decisions. However, the AER is concerned at the extent to which relevant policies or procedures do not appear to have been consistently applied in practice, and the implications that this may have for the effective and efficient identification of investment priorities in Ergon Energy's capex proposal. The AER considers this to be relevant in determining whether Ergon Energy's forecast capex reasonably reflects the capex criteria.

G.5.2 Cost estimation processes

This section examines the methods adopted by Ergon Energy to estimate costs for identified investment needs in the context of determining whether the AER is satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria.

Ergon Energy regulatory proposal

Ergon Energy has two broad categories of capex for the purposes of forecasting: specified work that includes discrete tasks of a relatively predictable nature, and unspecified work that includes tasks that are more difficult to specify in advance but which have a high probability of occurring.[1493]

To forecast the cost of specified capex work, which accounts for the majority of the capex program, Ergon Energy has applied a bottom up method whereby the unit costs of specified capex tasks are multiplied by the number of these tasks expected to be performed over the next regulatory control period.[1494]

Approximately 85 per cent of Ergon Energy's unit costs are derived from an internally developed estimating tool which takes account of factors such as the cost of internal and external labour and materials associated with specified capex tasks.[1495]

The remaining 15 per cent of Ergon Energy's unit costs are based on the following:[1496]

- historical rates derived by review of activities during Ergon Energy's budgeting process

[1491] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1492] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1493] Ergon Energy, *Regulatory proposal*, July 2009, p. 326.
[1494] Ergon Energy, *Regulatory proposal*, July 2009, p. 326.
[1495] Ergon Energy, *Regulatory proposal*, July 2009, p. 327.
[1496] Ergon Energy, email response to AER, Q.AER.ERG.05, 4 September 2009.

- contractor rates where these are available and suitable
- custom estimates for low value and/or one-off small specified capital works.

Costs for the units that make the 10 largest contributions to Ergon Energy's capex on a volume weighted basis are presented in table G.4.

Table G.4: Ergon Energy's highest 10 capex unit costs for the next regulatory control period – confidential

Capex unit	Unit cost ($m)	Share of system capex (%)
25MVA urban zone substation		
66kV single circuit concrete pole 5km subtransmission line		
Upgrade (replace) transformers and associated works		
Underground 132/66kV sub-transmission line 1km		
Re-build 66kV line		
Underground feeder-light urban		
Rural zone substation – 6.3MVA transformer with fuses		
Overhead line reconductor – urban		
132kV double circuit concrete pole sub-transmission line 5km		
Sub-transmission pole top assembly – pole top replacement		
Total		

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 325.

To forecast the cost of unspecified capex work, Ergon Energy has applied a top down approach based on an extrapolation of historical expenditure to reflect expected changes in the cost and scope of the works over the regulatory control period.[1497]

Ergon Energy stated that its unit rates are efficient for a number of reasons, including:[1498]

- an independent review of its unit rates by Sinclair Knight Merz (SKM) suggests they are well within an acceptable range
- around 80 per cent of its capex costs are externally procured and therefore market tested

[1497] Ergon Energy, *Regulatory proposal*, July 2009, p. 326.
[1498] Ergon Energy, *Regulatory proposal*, July 2009, p. 330.

- it has well established and robust processes for developing its capital program, including in the areas of procurement, design and construction, and internal cost estimation.

Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of Ergon Energy's capex forecast.

While not required to provide a comprehensive benchmarking review of unit costs, PB was required, as part of developing its view on the efficiency of investment decisions, to undertake a review of unit costs where it considered this was necessary.

In order to make this determination, PB adopted a phased approach, involving initial broad coverage of the expenditure proposal while enabling a more detailed examination of key issues as required.[1499] PB reviewed the cost estimation processes and procedures, including the development of unit costs for Ergon Energy's specified work and the range of methods used to develop costs for Ergon Energy's unspecified work. In addition to reviewing Ergon Energy's proposal and supporting documentation, PB conducted two rounds of detailed discussions with Ergon Energy staff.

PB noted that an independent review by SKM found that Ergon Energy's unit costs were within a nominated tolerance range of +/- 15 per cent and that SKM concluded the unit rates were 'reasonable and efficient cost estimates for the assets'.[1500]

Based on its review, PB concluded that the processes and procedures Ergon Energy uses in relation to cost estimation reflect good electricity industry practice.[1501]

AER considerations

The AER notes Ergon Energy's view that its unit rates are efficient because around 80 per cent of its capex costs are externally procured and therefore market tested. The AER considers that reliance on external competitive tender processes for the provision of capex related materials and services is likely to result in efficient costs being incurred by a DNSP. This conclusion, however, requires competitive tensions in the supply market.

The AER also notes Ergon Energy's claims that it has well established and robust processes for developing its capital program, including in the areas of procurement, design and construction, and internal cost estimation. The claims regarding procurement, design and construction are supported by PB's findings in relation to the deliverability of Ergon Energy's proposed works program (see section G.5.6) and cost estimation processes (discussed above).

The AER notes that 85 per cent of Ergon Energy's proposed capex is based on unit costs independently reviewed by SKM. The AER considers that SKM's review was sound and that its conclusions are valid because it:

1499 PB, *Report – Ergon Energy,* October 2009, p. 3.
1500 PB, *Report – Ergon Energy,* October 2009, p. 33.
1501 PB, *Report – Ergon Energy,* October 2009, p. 33.

- compared Ergon Energy's standard unit costs to SKM's current reference unit costs for similar parcels of work

- was based on a sample of unit costs that covered a broad range of asset classes and that represented a significant (28 per cent) share of Ergon Energy's proposed capex

- considered the efficiency of unit costs from three perspectives, including technical specification, individual unit cost efficiency and the overall impact on the regulatory proposal.

As a result, the AER considers that Ergon Energy's unit cost estimates are reasonable and efficient.

The AER also notes PB's conclusion that the processes and procedures Ergon Energy uses in relation to cost estimation reflect good electricity industry practice.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, and advice from PB and SKM, the AER is satisfied that Ergon Energy's cost estimation processes reasonably reflect the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

G.5.3 Application of input cost escalators

This section examines whether the cost escalators used by Ergon Energy to develop its capex proposal reflect a realistic expectation of input costs required to meet the capex objectives, in the context of determining whether the AER is satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria. While cost escalation affects capex sub-categories, the impacts of cost escalation, including any adjustments required by the AER, are treated in aggregate in this section only.

Ergon Energy regulatory proposal

Ergon Energy engaged SKM to develop cost escalators to apply to its capex forecasts, on the basis that the consumer price index does not accurately reflect movements in its nominal costs.[1502]

SKM identified the key factors influencing Ergon Energy's costs and their contributions to the total cost of items of plant, equipment and materials that comprise network assets. Key factors identified by SKM included oil, labour, construction costs, foreign exchange costs and materials such as copper, aluminium and steel.[1503]

SKM updated its October 2008 escalation rates in January 2009 to account for the latest forecast movements in the various cost drivers.[1504]

The methods used by SKM to calculate the escalation rates for Ergon Energy's key input costs are discussed in more detail in appendix H.

[1502] Ergon Energy, *Regulatory proposal*, p. 335.
[1503] Ergon Energy, *Regulatory proposal*, p. 337.
[1504] Ergon Energy, *Regulatory proposal*, p. 336.

SKM mapped changes in the cost of individual items of plant, equipment and materials to changes in the cost of network infrastructure projects and asset classes through the application of established project building blocks. These building blocks are specific proportions of labour and materials based on standard unit rate estimates developed by SKM for asset valuation and capital asset comparisons. For non–network capex, Ergon Energy applied escalation rates developed by SKM for non–network assets, including land and easements, IT systems, motor vehicles and buildings.[1505]

Ergon Energy's real cost escalators for capex are presented in table G.5.

SKM reviewed the application of its cost escalators by Ergon Energy in its internal models and warranted that Ergon Energy applied the escalators in the manner SKM intended.[1506]

The impact of Ergon Energy's proposed input cost escalators is illustrated in table G.6.

[1505] Ergon Energy, *Regulatory proposal*, July 2009, p. 338.
[1506] Ergon Energy, *Regulatory proposal*, July 2009, p. 339.

Table G.5: Ergon Energy real cost escalators for capex by asset category

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Overhead subtransmission lines	1.001	0.951	0.953	1.023	1.027	1.020	1.021	1.027
Underground subtransmission cables	1.009	1.009	0.957	1.011	1.018	1.013	1.010	1.017
Overhead distribution lines	0.991	1.018	0.933	1.014	1.027	1.024	1.022	1.028
Underground distribution cables	0.984	1.036	0.949	1.012	1.020	1.017	1.013	1.020
Distribution equipment	0.968	1.014	0.913	1.007	1.022	1.019	1.017	1.023
Substation bays	0.972	1.011	0.931	1.007	1.018	1.013	1.009	1.015
Substation establishment	0.999	1.009	1.000	1.019	1.013	0.995	0.985	0.996
Distribution substation switchgear	0.947	1.003	0.842	0.999	1.026	1.022	1.016	1.024
Zone transformers	0.993	1.002	0.766	1.002	1.047	1.039	1.029	1.041
Distribution transformers	0.996	1.012	0.889	1.009	1.030	1.025	1.020	1.028
Low voltage services	1.016	0.959	0.854	1.004	1.037	1.036	1.037	1.046
Metering	0.968	1.021	0.950	1.007	1.015	1.014	1.013	1.016
Communications - pilot wires	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Generation assets	0.956	1.020	0.871	1.009	1.032	1.025	1.018	1.026
Street lighting	0.992	1.015	0.977	1.013	1.018	1.014	1.013	1.017
Other equipment	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Control centre – SCADA	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Land and easements								
Residential	1.078	1.087	1.100	1.098	1.094	1.094	1.098	1.103
Commercial	1.034	1.042	1.055	1.054	1.050	1.050	1.054	1.058
Rural	1.060	1.068	1.081	1.080	1.076	1.076	1.080	1.084
Other	1.030	1.038	1.050	1.049	1.045	1.045	1.049	1.053
Communications	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
IT systems	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Office equipment and furniture	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Motor vehicles	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Source: Ergon Energy, *Regulatory proposal*, July 2009, AR539c SC Opex and Capex model.

Table G.6: Impact of Ergon Energy's cost escalator factors

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base capex ($m, 2007–08)	1013.4	1107.5	1091.2	1141.1	1238.8	5592.0
Inflation adjustment	46.1	50.4	49.6	51.9	56.3	254.3
Escalation adjustment	26.7	42.1	36.5	35.1	46.4	186.6
Capex with real cost escalators ($m, 2009–10)	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9

Source: Ergon Energy, response to AER question AER.ERG.14, 23 September, 2009.

Consultant review

PB was not required to assess forecast rates of growth in Ergon Energy's input costs (this exercise has been undertaken by the AER and is described in detail in appendix H of this draft decision). However, as part of its review, PB was required to ensure that forecast changes in input costs have been appropriately reflected in the cost escalation calculations performed by Ergon Energy in forecasting capex.

PB reviewed the analysis that SKM undertook for Ergon Energy in relation to cost escalation for capex, noting that it results in escalation indices that are directly applicable to Ergon Energy's breakdown of forecast capex into asset classes. PB considered this to be a detailed approach that is suitable for application to Ergon Energy's forecast capex.[1507]

PB noted that Ergon Energy was unable to provide the weightings used by SKM to derive the asset class escalators for capex due to protection of SKM's intellectual property. In order to form a view about the appropriateness of the weightings used by SKM, PB compared the resultant escalators to escalators based on its own high-level estimates of typical weightings. On this basis, PB concluded that the results of applying the SKM weightings as used by Ergon Energy are efficient.[1508]

PB noted that Ergon Energy applied the capex asset class escalators calculated by SKM in a spreadsheet model for forecasting capex. The model works by performing the following steps and calculations:[1509]

- input values are real annual escalators for 2005–06 to 2014–15 for each asset category as per the SKM analysis
- cumulative nominal escalators with a 2004–05 base are calculated by multiplying the above annual real escalators by the cumulative CPI index for each year since 2004–05
- the cumulative nominal escalators above are re-based to 2007–08

[1507] PB, *Report – Ergon Energy*, October 2009, p. 12.
[1508] PB, *Report – Ergon Energy*, October 2009, p. 12.
[1509] PB, *Report – Ergon Energy*, October 2009, p. 12.

- these escalators are applied to expenditure forecasts in 2007–08 dollars for financial years 2008–09 to 2014–15 to arrive at expenditure forecasts in nominal dollars

- the expenditure forecasts in nominal dollars are deflated back to 2009–10 dollars as required by the RIN by dividing through by the cumulative CPI index since 2009–10.

PB identified two problems with the workings of the model:[1510]

- the calculation of cumulative nominal escalators in step 2 includes the cumulative effect of CPI but not of the escalators themselves

- the set of CPI values used to inflate 2007–08 real values to nominal in step 2 is different from the set used to deflate back to 2009–10 real values in step 5.

PB calculated that correction of these issues results in a downward revision to forecast capex of $270 million ($2009–10) over the next regulatory control period.[1511]

The annual and total adjustments are shown in table G.7.

Table G.7: Recommended reduction in Ergon Energy capex arising from corrected real cost escalation ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
PB adjustment	–73.5	–72.7	–55.7	–41.3	–26.7	–269.9
PB recommendation	1012.7	1127.2	1121.6	1186.7	1314.8	5763.0

Source: PB, *Report – Ergon Energy*, October 2009, p. 12.

AER considerations

The AER assessed forecast rates of growth in Ergon Energy's input costs and PB was required to ensure that these forecasts have been appropriately reflected in the cost escalation calculations performed by Ergon Energy.

The AER's detailed consideration and conclusions on Ergon Energy's input cost escalators, and the methodologies underpinning those escalators, are set out at appendix H to this draft decision. The AER has not accepted the methodologies used to develop Ergon Energy's real cost escalators.

Ergon Energy applied a single escalation rate of 4.5 per cent, equal to its current annual EBA increase, to its total forecast internal labour and contract labour base forecasts for capex and opex. The AER does not consider this is appropriate because:

[1510] PB, *Report – Ergon Energy,* October 2009, p. 12.
[1511] PB, *Report – Ergon Energy,* October 2009, p. 12.

- it diminishes the commercial incentive for Ergon Energy to negotiate competitive wage outcomes
- it does not reflect forecast labour market conditions
- it does not differentiate between specialist and general labour resources.

The AER considers that forecast labour growth rates, specific to Queensland, are likely to reasonably reflect the efficient forecast rate of growth in labour costs for the next regulatory control period. In addition, the AER considers a weighted average escalation rate should be applied to Ergon Energy's contract and internal labour resources, based on the relative contribution of specialist and general labour resources.

The AER does not consider Ergon Energy's escalation rates for materials costs are acceptable because they do not reflect the most up to date market–based forecasts of future materials costs.

The AER notes PB's finding that the analysis that SKM undertook for Ergon Energy results in escalation indices that are directly applicable to Ergon Energy's breakdown of forecast capex into asset classes.

As Ergon Energy has used 27 asset classes for the purpose of forecasting capex, the AER considers that SKM's approach appears to be very detailed and therefore likely to accurately reflect real cost changes in assets over the next regulatory control period.

This is supported by PB's conclusion that SKM's approach is a detailed approach that is suitable for application to Ergon Energy's forecast capex.

While it would have been useful for PB to review the weightings used by SKM to prepare the asset class escalators for capex, the AER is satisfied that PB's use of its own high-level estimates of typical weightings provides a sound basis for review and therefore accepts PB's conclusion that the weightings applied by Ergon Energy are efficient.

The AER notes PB findings in relation to the application of capex cost escalators by Ergon Energy in its capex modelling. The AER has reviewed Ergon Energy's capex model and confirmed the errors found by PB.

The AER notes that Ergon Energy's failure to reflect the cumulative impact of real cost changes in calculating cumulative nominal cost escalators has the effect of over estimating forecast capex. This is because the real cost escalators calculated by SKM include real cost decreases for a number of key asset categories during 2007–08 to 2009–10, as shown in table G.5. The cumulative impact of these decreases is not appropriately reflected in Ergon Energy's modelling.

The AER also notes that the set of CPI values Ergon Energy used to inflate 2007–08 real values to nominal values are greater than those used to deflate back to 2009–10 real values. This has the effect of over-estimating Ergon Energy's forecast capex in $2009–10.

The AER requested Ergon Energy model the impact of the AER's draft decision on capex cost escalation on its forecast capex. Ergon Energy advised that the adjustment to forecast capex is $82 million ($2009–10).

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's application of real cost escalators reasonably reflects the capex criteria, including the capex objectives. The AER considers that increasing Ergon Energy's proposed capex by $82 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for capex to comply with the NER. In coming to this view the AER has had regard to the capex factors.

G.5.4 Review by expenditure type

This section examines the scope, timing and costs of Ergon Energy's proposed capex by major investment category in the context of determining whether the AER is satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria.

G.5.4.1 Growth capex

Ergon Energy regulatory proposal

Ergon Energy proposed growth capex of $3686 million ($2009–10). Total growth capex, which includes both CICW and CIA capex, represents approximately 61 per cent of the total forecast capex program. Ergon Energy's growth related capex is forecast to increase by approximately 52 per cent from the current regulatory control period.[1512] Table G.8 sets out Ergon Energy's proposed growth capex for the next regulatory control period.

Table G.8: Ergon Energy's proposed growth related capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Corporation initiated augmentation	267.8	339.4	401.3	463.6	518.9	1990.9
Customer initiated capital works	336.1	355.0	315.6	328.7	359.6	1695.0
Total growth capex	603.9	694.4	716.8	792.3	878.5	3685.9

Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
Note: Totals may not add due to rounding.

Corporation initiated augmentation

Approximately 54 per cent of the proposed growth capex is attributed to the CIA work described in Ergon Energy's sub-transmission and distribution network augmentation plans. Ergon Energy stated these plans describe the capital works needed to meet the augmentation requirements of the sub-transmission and distribution networks in each of its six geographic regions. The sub-transmission and

[1512] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.

distribution network augmentation plans form the basis of five and ten year capital works plans, which also reflect any reductions in demand that can be achieved through the implementation of efficient demand management initiatives.[1513]

Ergon Energy forecast its CIA expenditure to increase by approximately 90 per cent from the current regulatory control period. It attributed the increase to increased levels of work required for it to implement its network planning and security criteria, and to meet forecast peak demand and load growth. Ergon Energy noted peak demand and load growth are driven by strong population growth, major new industrial or commercial developments, economic growth, and climatic effects and air conditioning penetration.[1514]

Ergon Energy forecast annual network peak demand growth of 2.93 per cent over the next regulatory control period.[1515]

Customer initiated capital works

Ergon Energy stated CICW expenditure related to work required to service new or upgraded customer connections, and included:[1516]

- small customer connections
- new distribution network assets requested by customers or developers such as subdivision assets
- upstream distribution network augmentation work that relates directly to a new or upgraded customer connection.

The proposed CICW expenditure for the next regulatory control period has been developed using the actual 2007–08 level of expenditure as a baseline. Ergon Energy proposed to adjust the baseline expenditure to reflect current costs, dwelling stock growth forecasts prepared by the National Institute of Economic and Industry Research (NIEIR). Ergon Energy also proposed scope changes to reflect the increased contestability of residential subdivision, commercial and industrial work.[1517]

Ergon Energy forecast CICW expenditure to increase by approximately 23 per cent from the current regulatory control period. It attributed the proposed increase in expenditure to the baseline escalation process described above.[1518]

Ergon Energy estimated that it will recover approximately 33 per cent of total CICW expenditure through contributions from small customers, in accordance with its capital contributions policy. Ergon Energy forecast the level of customer contributions based on the actual 2007–08 level of contributions. It adjusted the baseline contributions to reflect current costs, dwelling stock growth forecasts

1513 Ergon Energy, *Regulatory proposal*, July 2009, pp. 200–202.
1514 Ergon Energy, *Regulatory proposal*, July 2009, p. 237.
1515 Ergon Energy, *Regulatory proposal*, July 2009, p. 17.
1516 Ergon Energy, *Regulatory proposal*, July 2009, p. 204.
1517 Ergon Energy, *Regulatory proposal*, July 2009, p. 207.
1518 Ergon Energy, *Regulatory proposal*, July 2009, pp. 237–238

prepared by NIEIR, and scope changes reflecting the increased contestability of residential subdivision, commercial and industrial work.[1519]

Consultant review

PB reviewed Ergon Energy's proposed growth related capex for the next regulatory control period, including both the CIA and CICW proposed expenditures. Its review considered the drivers of these categories of expenditure and the application of key policies and procedures including Ergon Energy's planning criteria, options analysis and cost estimation procedures. PB also reviewed Ergon Energy's consideration of non–network alternatives and the application of the demand forecast.[1520]

A separate independent review of Ergon Energy's peak demand forecasts was undertaken for the AER by McLennan Magasanik Associates (MMA). The outcomes of this review are discussed in detail in chapter 6. In reviewing Ergon Energy's proposed growth related capex, PB assessed the sensitivity of the CIA expenditure to the demand forecast. PB took account of MMA's recommendations on Ergon Energy's peak demand forecast in making its recommendations on Ergon Energy's proposed CIA expenditure, as discussed below.[1521]

PB found that Ergon Energy's planning criteria are in accord with good electricity industry practice. PB considered the planning criteria to be appropriately applied and suitable for the purposes of developing the CIA capex forecast.[1522] PB found that the cost estimation processes used by Ergon Energy also reflected good electricity industry practice.[1523]

PB found the quality, completeness and robustness of Ergon Energy's options analysis for addressing identified network constraints varied considerably. PB concluded that although Ergon Energy's procedures are prudent in requiring options analysis to be conducted, the inconsistent and incomplete application of the process did not clearly demonstrate efficient investment decisions.[1524]

In reviewing the extent to which Ergon Energy considers efficient non–network alternatives to address identified network constraints, PB found that non–network alternatives are rarely recognised as potential options. However, PB noted that Ergon Energy was focussing on trials and pilot programs to develop the necessary skills and expertise in this area. Given Ergon Energy's current stage of development, PB considered it was broadly in line with good electricity industry practice in this regard.[1525]

PB indicated that for the CIA capex proposal, where business case documents were available they clearly addressed the need and timing for the proposed expenditure. However, PB found that in some instances the options analysis was not robust, and that Ergon Energy was unable to provide business cases or similar documentation in a

[1519] Ergon Energy, *Regulatory proposal*, July 2009, pp. 420–421.
[1520] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1521] PB, *Report – Ergon Energy*, October 2009, p. 36.
[1522] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1523] PB, *Report – Ergon Energy*, October 2009, p. 33.
[1524] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1525] PB, *Report – Ergon Energy*, October 2009, p. 35.

number of instances.[1526] PB also stated it was unable to establish a clear relationship between the relevant planning documentation and the CIA capex proposal.[1527] PB was therefore unable to conclude that the CIA capex proposal was efficient.[1528]

MMA's review of Ergon Energy's peak demand forecasts found, in summary, that the forecasts were likely to be overstated to the extent of one to two years of peak demand growth.[1529] PB therefore analysed the impact on the demand related CIA forecast of a one or two year deferral of demand growth.[1530] As a result, PB recommended that Ergon Energy's proposed demand related CIA capex be reduced by $526 million, the equivalent of 18 months of demand related expenditure. PB calculated this figure on the basis of the average of the one and two year capex deferral analyses.[1531]

In relation to the proposed CICW capex, PB had a number of concerns regarding the applicability of various growth forecasts used by Ergon Energy as part of its CICW forecasting methodology. PB considered that insufficient supporting information was available to justify the CICW forecasts, and that it was therefore unable to conclude that the proposed CICW capex was efficient.[1532]

PB constructed a model to produce a 'business as usual' CICW capex forecast based on Ergon Energy's average historical connection numbers and costs, and escalated by the forecast customer growth rate.[1533] Given its concerns about Ergon Energy's methodology, PB recommended that this business as usual approach to forecasting CICW expenditure be adopted, resulting in a reduction of $318 million to Ergon Energy's proposed CICW capex.[1534]

Overall, PB found that Ergon Energy's proposed growth related capex was not prudent and efficient and recommended a reduction of $844 million to Ergon Energy's proposed expenditure of $3686 million.[1535]

AER considerations

The AER reviewed Ergon Energy's growth related capex proposal for the next regulatory control period. The AER considered the documentation provided by Ergon Energy in support of its regulatory proposal, and sought advice from PB about the prudence and efficiency of the proposed expenditures.

The AER received submissions from the EUAA and QCOSS seeking assurances that Ergon Energy's demand management activities are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[1536] The AER notes that Ergon Energy included its proposed demand management

[1526] PB, *Report – Ergon Energy*, October 2009, p. 37.
[1527] PB, *Report – Ergon Energy*, October 2009, p. 38.
[1528] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1529] MMA, *Review of Energex's demand forecasts*, October 2009, p. 8.
[1530] PB, *Report – Ergon Energy*, October 2009, p. 36.
[1531] PB, *Report – Ergon Energy*, October 2009, p. 38.
[1532] PB, *Report – Ergon Energy*, October 2009, p.41.
[1533] PB, *Report – Ergon Energy*, October 2009, p. 39
[1534] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1535] PB, *Report – Ergon Energy*, October 2009, p. 43.
[1536] EUAA, *Submission to the AER*, August 2009, pp. 20–21; QCOSS, *Submission to the AER*, August 2009, pp. 3–4.

expenditure as part of its opex proposal, which is discussed in chapter 8 of this draft decision.[1537] Nevertheless, the AER reviewed the extent to which Ergon Energy has considered, and made provision for, efficient non–network alternatives in its growth capex proposal, and also sought PB's advice in this regard.

The AER notes PB's finding that non–network alternatives are rarely recognised as potential options, but that given Ergon Energy's current stage of development, PB considered it was broadly in line with good electricity industry practice in this regard.[1538] The AER notes that capex on non–network alternatives is typically linked to the outcomes of regulatory test processes.[1539] While this should ensure the efficiency of the selected non–network alternative where applied, the AER notes that such an approach limits the extent to which non–network alternatives are considered to circumstances where the regulatory test process is applied (augmentation projects greater than $10 million).

On the basis of its review, and advice from PB, the AER considers that the extent to which Ergon Energy has considered and made provision for efficient non–network alternatives as part of its capex proposal is limited. However, noting Ergon Energy's approach of including proposed demand management expenditure as part of its opex proposal, the AER is generally satisfied that Ergon Energy does consider, and make provision for, efficient non–network alternatives and demand management initiatives.

The AER notes that growth capex accounts for a significant 61 per cent of Ergon Energy's total forecast capex program, and is forecast to increase by approximately 52 per cent from the current regulatory control period.[1540]

In relation to Ergon Energy's policies and procedures for planning the proposed CIA capex, the AER notes PB's findings that:

- Ergon Energy's planning criteria, while inherently conservative, are in accord with good electricity industry practice, are appropriately applied and suitable for the purposes of developing the CIA capex forecast[1541]
- the cost estimation processes used by Ergon Energy reflect good electricity industry practice[1542]
- the quality, completeness and robustness of Ergon Energy's options analysis for addressing identified network constraints varies considerably, and the inconsistent and incomplete application of the process did not clearly demonstrate efficient investment[1543]
- where business case documents are available, they clearly addressed the need and timing for the proposed expenditure. However in some instances the options

[1537] Ergon Energy, *Regulatory proposal*, July 2009, p. 313.
[1538] PB, *Report – Ergon Energy*, October 2009, p. 35.
[1539] Ergon Energy, *Regulatory proposal*, July 2009, p. 313.
[1540] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
[1541] PB, *Report – Ergon Energy*, October 2009, p. 40.
[1542] PB, *Report – Ergon Energy*, October 2009, p. 33.
[1543] PB, *Report – Ergon Energy*, October 2009, p. 40.

analysis is not robust, and Ergon Energy was unable to provide business cases or similar documentation in a number of instances where PB considered such documentation to be necessary to demonstrate the prudence and efficiency of expenditure[1544]

- a clear relationship between the relevant planning documentation and the CIA capex proposal was not evident.[1545]

The AER notes that PB was unable to conclude that the CIA capex proposal was efficient.[1546]

The AER considers that these findings, in particular the lack of business case or other supporting documents and inconsistent or incomplete options analysis processes, support a view that the need, timing and efficiency of the proposed capex has not been established by Ergon Energy. The AER is therefore not satisfied that the forecast growth related capex reflects the efficient costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the capex objectives set out in the NER.

The AER notes that peak demand growth is a key driver of growth related capex, and Ergon Energy forecast annual network peak demand growth of 2.93 per cent over the next regulatory control period.[1547] The AER sought advice from MMA about the reasonableness of Ergon Energy's peak demand and sales forecasts, and from PB about whether these forecasts had been appropriately applied by Ergon Energy in the preparation of its capex proposal. The AER notes PB's view that the prudent application of the demand forecast set out in Ergon Energy's regulatory proposal had been only partially demonstrated and evidenced by the business documentation.[1548] Further, as discussed in chapter 6 of this draft decision, the AER notes the advice from MMA that Ergon Energy's peak demand forecasts are not realistic and are likely to be overstated to the extent of one to two years of peak demand growth.[1549]

The AER is therefore not satisfied that Ergon Energy's forecast CIA capex reasonably reflects a realistic expectation of the demand forecast required to achieve the capex objectives set out in the NER. The AER considers it appropriate that Ergon Energy's proposed demand related CIA capex be reduced to account for its overestimation of forecast maximum demand in the next regulatory control period. The AER notes PB's recommendation that Ergon Energy's proposed CIA capex be reduced by $526 million, the equivalent of 18 months of demand related expenditure.[1550] The approach recommended by PB for determining this reduction is to reduce the total forecast MVA growth in peak demand over the next regulatory control period by the average of one to two years (18 months) average MVA growth, and apply these revised forecasts to the demand related component of forecast CIA capex.[1551] The

[1544] PB, *Report – Ergon Energy*, October 2009, p. 37.
[1545] PB, *Report – Ergon Energy*, October 2009, p. 38.
[1546] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1547] Ergon Energy, *Regulatory proposal*, July 2009, p. 17.
[1548] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1549] MMA, *Review of Ergon Energy's maximum demand forecasts*, September 2009, p. 8.
[1550] PB, *Report – Ergon Energy*, October 2009, p. 38.
[1551] PB, *Report – Ergon Energy*, October 2009, p. 36.

AER has reviewed this approach and considers it provides a reasonable approach to determining a substitute forecast CIA capex allowance, reflecting a realistic expectation of demand. The AER requested Ergon Energy model the impact of the AER's draft decision on CIA capex. Ergon Energy advised that the adjustment to forecast CIA capex is a reduction of $526 million ($2009–10).

In relation to the proposed CICW capex, the AER notes that PB identified a number of concerns regarding the applicability of various growth forecasts used by Ergon Energy as part of its CICW forecasting methodology.[1552] The AER notes PB's view that insufficient supporting information was available to justify the CICW forecasts, and that it was therefore unable to conclude that the proposed CICW capex was efficient.[1553]

Based on its review, and PB's advice, the AER considers that the robustness of Ergon Energy's forecast CICW capex is not supported by Ergon Energy's forecasting methodology. For example, the AER considers that the application of dwelling stock growth forecasts in order to forecast growth in commercial and industrial connections is not appropriate.

PB's proposed approach to determining a prudent and efficient level of CICW capex is to apply a business as usual approach. PB constructed a model to produce a business as usual CICW capex forecast based on Ergon Energy's average historical connection numbers and costs, and forecast customer growth rate.[1554] The AER notes that PB's recommended business as usual approach to CICW expenditure results in a reduction of $318 million to Ergon Energy's proposed CICW capex.[1555]

The AER has reviewed this approach and considers it provides a reasonable approach to determining a substitute forecast CICW capex allowance, noting that PB's recommended CICW allowance is consistent with CICW expenditure in the current regulatory control period. The AER requested Ergon Energy model the impact of the AER's draft decision on CICW capex. Ergon Energy advised that the adjustment to forecast CICW capex is a reduction of $318 million ($2009–10).

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's growth related capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed growth capex by $844million[1556] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

[1552] PB, *Report – Ergon Energy*, October 2009, p. 39.
[1553] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1554] PB, *Report – Ergon Energy*, October 2009, p. 39.
[1555] PB, *Report – Ergon Energy*, October 2009, p. 41.
[1556] See table G.19 for the treatment of the shared cost component of this deduction.

G.5.4.2 Replacement and renewal capex

Ergon Energy regulatory proposal

Ergon Energy forecast an amount of $1214 million ($2009–10) for asset replacement capex during the next regulatory control period, an increase of 72 per cent (in real terms) compared to the current regulatory control period. Forecast replacement and renewal capex represents approximately 20 per cent of Ergon Energy's total forecast capex program. Table G.9 sets out Ergon Energy's proposed asset replacement capex for each year of the next regulatory control period.

Table G.9: Ergon Energy's proposed asset replacement capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement/renewal	177.4	212.7	250.0	274.8	299.2	1214.1

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 193.

Ergon Energy stated that its asset replacement program focuses on assets in poor condition and most likely to fail in service – generally assets approaching the end of their lives but also includes assets that fail early.[1557]

Ergon Energy developed asset equipment plans (AEPs) for each of its 26 asset classes. The AEPs provide growth rates and cycle times for each asset equipment type and consider the current situation, maintenance policies, issues and challenges and strategies for change and improvement. AEPs are used to plan long term annual expenditure up to at least 2017.[1558]

Ergon Energy's network asset replacement maintenance capital expenditure operating expenditure summary (NARMCOS) model forecasts asset replacement expenditure across the classes of system assets. The forecasts are derived by considering the preventive maintenance programs, estimated defect rates and unit rates.[1559]

Ergon Energy has split its asset replacement capex into two categories, defects and condition based.

Defects

Defect capex relates to assets that have failed or are expected to fail and are identified through the preventative maintenance opex program. Defects also include repair and replacement following the failure of major items of plant such as underground cables and transformers.[1560]

Ergon Energy stated key changes to defect related forecast asset replacement capex during the next regulatory control period (compared to the current regulatory control period) include:[1561]

[1557] Ergon Energy, *Regulatory proposal*, July 2009, p. 193.
[1558] Ergon Energy, *Regulatory proposal*, July 2009, pp. 195–196.
[1559] Ergon Energy, *Regulatory proposal*, July 2009, pp. 195–196.
[1560] Ergon Energy, *Regulatory proposal*, July 2009, p. 193.
[1561] Ergon Energy, *Regulatory proposal*, July 2009, p. 197.

- pole top replacements required as a result of an increase in the number of unassisted failures and events relating to cross arms
- replacement of underground cables, including XLPE cables due to increased failures
- replacement of lightning arrestors
- replacement of customer overhead service lines
- earth remediation works
- replacement of non compliant meters.

Condition based

Ergon Energy stated that condition based asset renewal capex is driven by specific issues such as failure characteristics of assets, unserviceability and obsolescence of assets, bulk asset replacement and replacement due to unavailability of spare parts.[1562] Condition based capex predominantly relates to sub–transmission zone substations and secondary systems assets.[1563]

Ergon Energy stated key changes to condition based asset replacement capex during the next regulatory control period (compared to the current regulatory control period) include:[1564]

- distribution lines:
  - increased capex on overhead conductors in accordance with the EDSD Review and the Queensland government initiated operational review. The conductor replacement program commenced in 2008–09 to combat damage caused by local environmental conditions such as corrosion, lightning strikes, cane fire damage, vibration and annealing
  - replacement of liquid filled fuses to address safety concerns identified during the current regulatory control period
- sub–transmission lines:
  - increased capex on pole top refurbishment following condition assessments, feeder performance and risks to the network
  - rebuilding of sub–transmission lines to meet service performance requirements
- substation plant and equipment capex for the replacement and/or refurbishment of power transformers, circuit breakers, current and voltage transformers, SCADA, protection equipment, capacitors and outdoor switchyard refurbishment
- communication systems.

[1562] Ergon Energy, *Regulatory proposal*, July 2009, p. 194.
[1563] Ergon Energy, *Regulatory proposal*, July 2009, p. 194.
[1564] Ergon Energy, *Regulatory proposal*, July 2009, pp. 197–198.

Consultant review

PB reviewed the drivers for asset replacement capex as well as the application of key policy and procedures, and undertook specific reviews to determine the basis of Ergon Energy's asset replacement capex forecasts.[1565]

PB noted that there are two main drivers for Ergon Energy's asset replacement expenditure, namely defects and condition-based replacement. PB expected that a prudent and efficient business following good electricity industry practice would have a sound understanding of the condition of its assets.[1566] Therefore, PB considered Ergon Energy had identified appropriate drivers for the proposed asset replacement expenditure.[1567]

PB reviewed Ergon Energy's key policy and procedural documents with respect to asset replacement, including the:[1568]

- Asset Management Defect Policy
- Strategic Plan for Asset Renewal
- Network Defect Classification Manual.

PB also reviewed other examples of asset strategy documentation, such as the Meter Asset maintenance Strategy, Instrument Transformer Asset Maintenance Strategy and AEPs.[1569]

PB found that Ergon Energy has an extensive and well–integrated documentation framework. Although still being implemented, PB considered Ergon Energy demonstrated a thorough framework for the management of asset replacement. PB had some concerns regarding the current level of implementation of Ergon Energy's replacement practices when considered from the perspective of relevant standards and current good electricity industry practice.[1570] These concerns are discussed in detail below. Notwithstanding these concerns, PB concluded that Ergon Energy's key policies and procedures relating to the development of the asset replacement capex proposal generally accord with the principles of good asset management and good electricity industry practice.[1571]

PB noted that where the replacement rate for particular assets is increasing over time, a condition-based replacement approach can curb the rate of increase better than an age-based approach.[1572] PB stated that good electricity industry practice is to use a condition-based replacement approach.[1573] PB is concerned that Ergon Energy,

[1565] PB, *Report – Ergon Energy*, October 2009, p. 53.
[1566] PB, *Report – Ergon Energy*, October 2009, p. 42.
[1567] PB, *Report – Ergon Energy*, October 2009, p. 43.
[1568] PB, *Report – Ergon Energy*, October 2009, p. 43.
[1569] PB, *Report – Ergon Energy*, October 2009, p. 43.
[1570] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1571] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1572] PB, *Report – Ergon Energy*, October 2009, p. 54.
[1573] PB, *Report – Ergon Energy*, October 2009, p. 54.

although it purports to use a condition-based approach to asset replacement, still utilises, in many instances, an age-based approach.[1574]

PB stated that it has concerns regarding the current level of implementation of Ergon Energy's replacement practices when considered from the perspective of the relevant standards and current good electricity industry practice.[1575] PB noted that Ergon Energy partially utilises an age-based approach in determining its replacement capex forecasts.[1576] Additionally, PB have seen little evidence that risk analysis has been uniformly applied to the development of asset replacement capex programs, or that risk assessment is being routinely applied in asset replacement decisions.[1577] PB noted that Ergon Energy's asset replacement capex proposal has limited reliance on asset condition data or asset condition models based on asset population data. PB formed the view that Ergon Energy is only partially following condition-based asset renewal practices. PB stated that its view accords with Ergon Energy's *Strategic Plan for Asset Renewal* which notes there are seven significant issues affecting Ergon Energy's asset renewal process, namely:[1578]

- adoption and understanding the concept of refurbishment
- quality and availability of asset data (both asset data and condition information)
- application of risk analysis to asset renewal decisions is not yet universal or mature
- difficulty co-ordinating asset renewal works with other stakeholders/drivers
- relativity of renewal works priority against other business priorities
- funding and resource constraints due to large load growth, N–1 security requirements and high costs of work
- the lack of recognised maintenance and renewal methodologies.

PB stated that it generally agreed with the findings of Ergon Energy's *Strategic Plan for Asset Renewal*, and noted Ergon Energy's planned actions to move the business towards good electricity industry practice.[1579]

To assess the prudence and efficiency of Ergon Energy's asset replacement capex, PB investigated how the proposed replacement capex forecast had been modelled, focusing particularly on how the business established the replacement volume forecasts.[1580] PB noted that the AEPs form a primary input to the asset replacement

1574 PB, *Report – Ergon Energy*, October 2009, p. 54.
1575 PB, *Report – Ergon Energy*, October 2009, p. 54.
1576 PB, *Report – Ergon Energy*, October 2009, p. 54.
1577 PB, *Report – Ergon Energy*, October 2009, p. 54.
1578 PB, *Report – Ergon Energy*, October 2009, p. 54.
1579 PB, *Report – Ergon Energy*, October 2009, p. 54.
1580 PB, *Report – Ergon Energy*, October 2009, p. 44.

capex proposal and the actual asset replacement capex forecast is built up within Ergon Energy's NARMCOS model.[1581]

Ergon Energy advised PB that the historical data provided in the NARMCOS model is not accurate and should not be relied upon.[1582] PB sought actual historical costs and volumes for the line items in the NARMCOS model, but Ergon Energy was unable to provide this data. Consequently, PB's analysis focused on the forecast volumes and the related documentation supporting these volume estimates.[1583]

In order to examine how the proposed asset replacement capex forecast had been determined, PB conducted a high-level review of the top 10 asset replacement capex items and undertook detailed review of the four largest asset replacement capex items, including:[1584]

- pole tops replacement
- conductors and connectors replacement
- underground cables and joints replacement
- zone substation transformers replacement.

PB noted that the top four asset replacement capex expenditures over the next regulatory control period represent 48 per cent of the total proposed asset replacement capex.[1585]

Pole tops replacement

PB noted that Ergon Energy's pole top asset replacement capex represents 10 per cent of the total asset replacement capex proposal, and includes the replacement of over 43 000 pole tops in the next regulatory control period. PB also noted that after an initial increase in 2010–11, the forecast expenditure on pole top replacement generally levels off over the rest of the next regulatory control period.[1586]

During its review PB noted a number of concerns regarding the information provided by Ergon Energy to support its volume forecast for pole top replacements, particularly in the context of the proposed 72 per cent real increase over the current period for total asset replacement capex.[1587] PB noted that Ergon Energy's AEP states that forecast failure rates are assumed to remain consistent with current defect rates, as are the replacement rates, but with some allowance for new inspection programs. PB noted that pole top replacement is a new category of replacement capex and therefore

[1581] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1582] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1583] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1584] PB, *Report – Ergon Energy*, October 2009, p. 44.
[1585] PB, *Report – Ergon Energy*, October 2009, p. 45.
[1586] PB, *Report – Ergon Energy*, October 2009, p. 45.
[1587] PB, *Report – Ergon Energy*, October 2009, p. 47.

there are no historical volumes. PB has not been able to assess whether the proposed volume estimates are consistent with the AEP.[1588]

PB made enquires to establish what allowance had been made for the additional defects identified by the new inspection program. Ergon Energy provided analysis of the defect rates of pole tops resulting from the elevated work platform inspection program in Far North Queensland.[1589] PB found the pole top repair rates in 2006–07 for this particular inspection program were 7 per cent, and the cross arm replacement rates were 20 per cent. PB stated that, based on its experience, it considered this rate of failure to be very high.[1590]

PB also examined Ergon Energy’s Asset Management Strategy Document and noted that Ergon Energy’s cross arm failure rate of 0.670/(100 km, year) compares favourably with an industry benchmark produced by a Swedish University on insulator, cross arm failures, connectors and attachments, which shows a industry average failure rate of 0.93/(100 km, year).[1591]

PB stated it attempted to assess the basis of Ergon Energy’s volume estimates based on the limited information provided by the business. PB concluded that it is prudent for Ergon Energy to propose expenditure to replace pole tops that are in poor condition. However, PB was unable to clearly determine the basis of the pole top volume forecasts, and therefore did not conclude that the proposed pole top replacement expenditure is efficient.[1592]

Replacement of conductors and connectors

PB’s review focussed on how the volume estimates and the prudence and efficiency of the proposed conductor and connector replacement volumes were established.

PB found that the conductors and connectors AEP sets out a number of existing capital programs, as well as proposed new programs and proposed changes to existing programs. PB was only able to partially reconcile the view presented by the AEP with that presented in the NARMCOS model.[1593] PB found that the history presented in the NARMCOS model was incomplete and was advised by Ergon Energy that the historical figures in the NARMCOS model are not reliable.[1594] Consequently, PB was unable to reconcile this information in order to establish the basis of the volume forecasts for conductors and connectors.[1595]

PB also enquired about the basis of the volume forecasts for 66kV and 110/132kV line rebuilds. PB found that the information provided by Ergon Energy makes it apparent that the volume forecasts are estimated provisions based on a view of the

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[1588] PB, *Report – Ergon Energy*, October 2009, p. 47.
[1589] PB, *Report – Ergon Energy*, October 2009, pp. 45–46.
[1590] PB, *Report – Ergon Energy*, October 2009, p. 46.
[1591] PB, *Report – Ergon Energy*, October 2009, p. 46.
[1592] PB, *Report – Ergon Energy*, October 2009, p. 47.
[1593] PB, *Report – Ergon Energy*, October 2009, p. 48.
[1594] PB, *Report – Ergon Energy*, October 2009, p. 48.
[1595] PB, *Report – Ergon Energy*, October 2009, p. 48.

asset age, which contradicts Ergon Energy's strategy of undertaking asset replacement on a defect and condition basis.[1596]

PB also enquired about the proposed copper, steel and aluminium conductor steel reinforced replacement programs. PB found the responses from Ergon Energy were inconsistent with its stated approach in the AEP.[1597]

PB stated that while it is prudent for Ergon Energy to propose expenditure to replace and refurbish conductor and connector assets, such expenditure should be clearly justified on the basis of defect history and condition analysis, consistent with Ergon Energy's *Strategic plan for asset renewal*.[1598] PB also stated that Ergon Energy has been unable to provide information that sufficiently explains how the proposed asset replacement capex is prudent or efficient. PB found that many of Ergon Energy's volume estimates are age based that are not directly related to defect history or condition assessment. Therefore, PB can not conclude that the proposed conductors and connectors replacement capex is prudent or efficient.[1599]

Underground cables and joints replacement

PB noted that Ergon Energy's proposed underground cables and joints replacement capex represents 7 per cent of the total asset replacement capex. PB found that after an initial step change in 2010–11, expenditure on underground cables and joints replacement levels off over the next regulatory control period.[1600]

PB found that Ergon Energy has to some degree used historical defect rates when estimating the volume forecasts for underground cables and joints. PB considered this an appropriate approach. However, PB stated that Ergon Energy has been unable to provide its calculations to substantiate its methodology or to show the extent to which it has applied this approach.[1601]

PB also noted Ergon Energy has shown good electricity industry practice in the area of refurbishment. PB is of the view that Ergon Energy should be encouraged to continue its investigations into these practices.[1602]

PB noted Ergon Energy's allowance for age-based replacement, as well as its stated practice of assessing the suitability for repair or replacement of cables that fail in service. PB stated that while Ergon Energy's age-based replacement is not in line with good industry replacement practice, assessing failed cables for repair or replacement is good practice.[1603]

From the information provided, PB found that there is no major new expenditure proposed for this category of asset. PB also noted the AEP proposes a business as usual approach. Consequently, PB was satisfied that, for this asset category, the

[1596] PB, *Report – Ergon Energy*, October 2009, p. 48.
[1597] PB, *Report – Ergon Energy*, October 2009, pp. 48–49.
[1598] PB, *Report – Ergon Energy*, October 2009, p. 49.
[1599] PB, *Report – Ergon Energy*, October 2009, p. 49.
[1600] PB, *Report – Ergon Energy*, October 2009, p. 49.
[1601] PB, *Report – Ergon Energy*, October 2009, p. 50.
[1602] PB, *Report – Ergon Energy*, October 2009, p. 50.
[1603] PB, *Report – Ergon Energy*, October 2009, p. 50.

proposed expenditure represents a business as usual level of expenditure even though Ergon Energy has not been able to provide historical data.[1604] PB notes that business as usual expenditure may differ from historical expenditure in that historical expenditure includes abnormal under and over spends.[1605] PB concluded that it is prudent for Ergon Energy to propose expenditure on this category. PB also concluded that this expenditure is efficient because its analysis did not reveal any reason or factors to indicate that base (unescalated) forecasts should significantly differ from current regulatory control period expenditures.[1606]

Zone substation transformer replacement

PB found that Ergon Energy's zone substation transformer replacement capex represents 7 per cent of the total replacement capex proposal. PB noted that this expenditure is forecast to increase by an average of 49 per cent per annum over the next regulatory control period.[1607]

During its review, PB found that 94 per cent of the proposed transformer replacement capex is related to three proposed expenditures:[1608]

- general replacements (43 per cent)
- purchase of strategic spares (31 per cent)
- transformer dry–out (21 per cent).

PB reviewed the proposed zone substation transformer replacement expenditures. It noted that Ergon Energy's stated transformer management practices are generally consistent with good electricity industry practice.[1609] PB noted that approximately 6 per cent of the transformer population is forecast to be replaced during the next regulatory control period. PB found that Ergon Energy had not developed business cases for transformer replacement as replacement projects have been deferred due to funding constraints.[1610] PB concluded that there was no information provided to substantiate the volume forecast for the general replacement of transformers.[1611]

PB noted that the purchase of strategic spares is based on historical failure rates and these rates are much higher than general industry trends which most likely indicates an underlying asset management problem. PB was also concerned that the proposed transformer dry–out program volumes may be too low given the apparent state of the transformer population and its high failure rate.[1612] Additionally, PB found that while the AEP indicated that on–site transformer dry–out is likely to reduce costs, Ergon Energy modelling indicated that on–site costs are significantly higher than workshop

[1604] PB, *Report – Ergon Energy*, October 2009, p. 50.
[1605] PB, *Report – Ergon Energy*, October 2009, p. 4.
[1606] PB, *Report – Ergon Energy*, October 2009, p. 50.
[1607] PB, *Report – Ergon Energy*, October 2009, p. 50.
[1608] PB, *Report – Ergon Energy*, October 2009, p. 51.
[1609] PB, *Report – Ergon Energy*, October 2009, p. 51.
[1610] PB, *Report – Ergon Energy*, October 2009, p. 51.
[1611] PB, *Report – Ergon Energy*, October 2009, p. 53.
[1612] PB, *Report – Ergon Energy*, October 2009, p. 53.

dry–out costs.[1613] PB stated no information was provided to demonstrate that the dry–out program is efficient and effective. Consequently, PB did not conclude that the proposed transformer replacement capex is prudent or efficient.[1614]

Other review issues

Due to the lack of information to substantiate Ergon Energy's replacement capex proposals in the categories selected for detailed review, PB sought further information in relation to other asset replacement expenditure categories. In particular, PB wanted to examine the business risk associated with the asset replacement programs. That is to analyse the risk currently faced by the business, and the change in this risk due to the proposed asset replacement capex. In response to PB's enquiries, Ergon Energy stated that no specific documentation is prepared regarding the proposed change in risk, other than the details contained in the AEPs. Ergon Energy reported the change in risk is considered in the development of project business cases.[1615]

PB conclusion and recommendation

PB found that, with the exception of underground cables and joints replacement capex, the basis for the asset replacement volume forecasts could not be clearly demonstrated or substantiated.[1616] Consequently, PB concluded that the basis for the proposed real increase of 72 per cent for asset replacement capex in the next regulatory control period has not been demonstrated and therefore it was unable to conclude that the proposed asset replacement capex is prudent or efficient. Hence, PB recommended a business as usual level of funding.[1617]

PB considered that given Ergon Energy is incentivised to be efficient by the nature of CPI–X price regulation, a business as usual level of recurrent expenditure can be considered to be efficient.[1618] PB noted that a business as usual approach may differ from historical expenditures in so far as historical expenditures may include abnormal under and over spends.[1619]

PB noted that Ergon Energy's asset replacement capex which has shifted downwards from its historical growth rate largely reflects delays in expenditure to undertake higher priority capex in demand related areas.[1620] In order to establish a business as usual level of growth, PB ignored the current regulatory control period expenditure profile. PB calculated the historical growth rate during the most recent years of asset replacement capex increases for which data is available (2001–02 to 2005–06). PB then applied this growth rate to the asset replacement capex in the last year of the current regulatory control period to establish a business as usual forecast for the next regulatory control period.[1621] PB stated that this modelling results in total asset

[1613] PB, *Report – Ergon Energy*, October 2009, p. 52.
[1614] PB, *Report – Ergon Energy*, October 2009, p. 53.
[1615] PB, *Report – Ergon Energy*, October 2009, p. 53.
[1616] PB, *Report – Ergon Energy*, October 2009, pp. 54–55.
[1617] PB, *Report – Ergon Energy*, October 2009, p. 55.
[1618] PB, *Report – Ergon Energy*, October 2009, p. 4.
[1619] PB, *Report – Ergon Energy*, October 2009, p. 4.
[1620] PB, *Report – Ergon Energy*, October 2009, p. 55.
[1621] PB, *Report – Ergon Energy*, October 2009, p. 55.

replacement capex of $1095 million, representing a total reduction of $119 million or 9.8 per cent of the proposed asset replacement capex of $1214 million.[1622]

AER considerations

The AER notes that Ergon Energy forecast an amount of $1214 million ($2009–10) for asset replacement capex during the next regulatory control period, an increase of 72 per cent (in real terms) compared to the current regulatory control period. Forecast replacement and renewal capex represents approximately 20 per cent of Ergon Energy's total forecast capex program.

The AER notes that PB found that Ergon Energy has an extensive and well integrated documentation framework which, although still being developed, demonstrates a thorough framework for the management of asset replacement capex. Further PB noted that the key policies and procedures relating to the development of the proposed replacement capex program generally accord with the principles of good asset management and good electricity industry practice.[1623]

During its review, PB identified that despite claiming to use a condition based approach to asset replacement, Ergon Energy utilises an age based approach as well.[1624] A condition based approach uses a wide range of data including technical data (including asset age), historical routine maintenance and defect data as well as locational information to determine the condition and therefore the most appropriate timing for asset replacement. The AER considers that a condition based approach which takes into account a range of factors (one being asset age) is more likely to result in an efficient outcome.

The AER notes that Ergon Energy was unable to provide sufficient information to satisfy PB as to the basis for its forecast replacement volumes (with the exception of underground cables and joints replacement capex).[1625] If the forecasts have been based on sound information such as defect history and/or condition assessment, Ergon Energy should be able to provide that information to demonstrate the efficiency of its proposed replacement capex program. The AER considers forecast replacement volumes are a key driver of overall replacement capex and therefore must be accurate and reliable to develop a prudent and efficient forecast capex program.

Given Ergon Energy's inability to substantiate replacement volume forecasts and its use of an age based asset replacement approach rather than a condition based approach, the AER considers that Ergon Energy has not demonstrated that its forecast replacement capex is prudent and efficient. In accordance with the capex criteria, the AER must not accept the forecast.

The AER notes PB's approach to developing a business as usual level of expenditure. The asset replacement capex growth rate in the current regulatory control period has shifted downwards. Therefore the growth rate for the asset replacement capex for the period from 2001–02 to 2005–06 was applied to the asset replacement capex in the

[1622] PB, *Report – Ergon Energy*, October 2009, p. 55.
[1623] PB, *Report – Ergon Energy*, October 2009, p. 54
[1624] PB, *Report – Ergon Energy*, October 2009, p. 54.
[1625] PB, *Report – Ergon Energy*, October 2009, pp. 54–55.

last year of the current regulatory control period to establish a business as usual forecast. The AER has reviewed this approach and in the absence of verifiable data for asset replacement capex volumes and a condition based asset replacement program, considers it provides a reasonable approach to determining a substitute forecast asset replacement capex. The AER requested Ergon Energy model the impact of the AER's decision on asset replacement capex. Ergon Energy advised that the adjustment to forecast replacement capex is a reduction of $119 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast asset replacement capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed asset replacement capex by $119 million[1626] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

G.5.4.3 Reliability and quality improvement capex

Ergon Energy regulatory proposal

Ergon Energy forecast an amount of $122 million ($2009–10) for reliability and quality improvement capex during the next regulatory control period, an increase of 131 per cent (in real terms) compared to the current regulatory control period. Forecast reliability and quality improvement capex represents approximately 2 per cent of Ergon Energy's total forecast capex program. Table G.10 sets out Ergon Energy's proposed reliability and quality improvement capex for each year of the next regulatory control period.

Table G.10: Ergon Energy's reliability and quality improvement capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Reliability and quality improvements	18.3	20.9	24.5	28.3	30.4	122.4

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 208.

Ergon Energy stated that its reliability and quality improvement capex will address issues to meet externally and internally imposed service standards.[1627] It noted that its internally imposed service standards have been set solely for the purpose of meeting its externally set minimum service standards (MSS) within the Queensland Electricity Industry Code (EIC).[1628]

Ergon Energy stated that its forecast reliability and quality improvement capex is targeted at meeting its MSS and addressing its worst performing feeders by increasing the rollout of SCADA to around 90 per cent of all customers, delivering the feeder improvement program and extending the network monitoring program.[1629] It

[1626] See table G.19 for the treatment of the shared cost component of this deduction.
[1627] Ergon Energy, *Regulatory proposal*, July 2009, p. 209.
[1628] Ergon Energy, *Regulatory proposal*, July 2009, p. 209.
[1629] Ergon Energy, *Regulatory proposal*, July 2009, pp. 210–211.

proposed to focus on the 50 worst performing feeders at an average cost of $1 million per feeder.[1630]

Ergon Energy noted that some of its performance improvement will result from the continuation of its asset replacement, augmentation and network maintenance programs. It also stated that significant reliability performance improvement had been achieved during the current regulatory control period due to its defect related asset replacement program and relatively mild weather.[1631]

Consultant review

PB reviewed Ergon Energy's reliability and quality improvement capex proposal and considered the relevant performance standards, and the application of key policies and procedures. PB also undertook two specific reviews in order to establish the prudence and efficiency of the forecast capex.[1632]

PB noted Ergon Energy's proposed expenditure represents a real increase of 131 per cent when compared to the current regulatory control period.[1633] PB also noted that while the proposed expenditure on reliability and quality improvement is relatively small, it is the category with the largest real increase.[1634]

PB conducted a high-level review of the policies and procedures which Ergon Energy applied to meet its reliability and quality of supply standards. PB reviewed documents identified by Ergon Energy, including:[1635]

- network performance standard
- network performance strategy
- annual network performance report
- SCADA acceleration strategy
- feeder improvement program
- power quality strategic program.

PB stated that it is generally considered good practice to identify the worst performing network assets through a rigorous analysis of the business's network performance data, and then to target the specific causes and worst performance instances.[1636] PB also noted that while such an approach is prudent and efficient if undertaken rigorously, the timing and ranking for addressing such issues, as well as the opex and capex required, are also important for this analysis.[1637] PB considered that good

[1630] Ergon Energy, *Regulatory proposal*, July 2009, p. 210.
[1631] Ergon Energy, *Regulatory proposal*, July 2009, p. 210.
[1632] PB, *Report – Ergon Energy*, October 2009, p. 60.
[1633] PB, *Report – Ergon Energy*, October 2009, p. 55.
[1634] PB, *Report – Ergon Energy*, October 2009, p. 56.
[1635] PB, *Report – Ergon Energy*, October 2009, p. 57.
[1636] PB, *Report – Ergon Energy*, October 2009, p. 57.
[1637] PB, *Report – Ergon Energy*, October 2009, p. 57.

practice could be demonstrated through economic assessment and risk analysis of the efficient level of expenditure and provide for the revision of this analysis on an ongoing basis. PB stated this approach should be based on clearly defined and documented performance standards, and supported by policies, standards, strategies and robust data, as well as specific plans and procedures.[1638]

PB indicated that following its review of the reliability and quality improvement documents provided by Ergon Energy it was confident that the business has identified the worst performing parts of the network. PB noted that Ergon Energy developed specific strategies and plans to address the identified issues including network performance monitoring, a network remote control strategy, voltage regulation and power quality improvement plan and a feeder improvement program.[1639]

PB also noted Ergon Energy undertook a process of project ranking to develop a program of works that forms the basis of the budget planning process. It stated Ergon Energy expected to improve network reliability performance and customer service through improved fault isolation times and restoration times, particularly for the worst-performing distribution feeders.[1640]

PB found that Ergon Energy has adopted many of the elements of good electricity industry practice and documentation. PB concluded that Ergon Energy's policies and procedures in the area of management of reliability and quality of supply improvement are generally in accord with good electricity industry practice.[1641]

In reviewing the reliability and quality improvement capex, PB examined a range of planning documentation in order to review justification of the need and timing of the proposed capex, as well as the consideration of options and selection of the most efficient option.[1642]

PB stated that robust business cases or similar documentation should be available to provide justification for the proposed expenditure. PB examined the information contained in the SC Capex Data Model for the individual expenditure items under the reliability and quality improvement capex. PB noted that the SC Capex Data Model is used as an input to the regulatory proposal and applies unit costs to the forecast number of the assets that Ergon Energy proposes to build.[1643]

PB reviewed the supporting documentation for the two largest reliability and quality improvement capex items in the SC Capex Data Model, namely:[1644]

- Feeder improvement program – targeting red feeders (33 per cent of reliability and quality capex)[1645]

[1638] PB, *Report – Ergon Energy*, October 2009, p. 57.
[1639] PB, *Report – Ergon Energy*, October 2009, p. 57.
[1640] PB, *Report – Ergon Energy*, October 2009, pp. 57–58.
[1641] PB, *Report – Ergon Energy*, October 2009, p. 58.
[1642] PB, *Report – Ergon Energy*, October 2009, p. 58.
[1643] PB, *Report – Ergon Energy*, October 2009, p. 58.
[1644] PB, *Report – Ergon Energy*, October 2009, p. 58.

- SCADA installation (28 per cent reliability and quality capex).

Feeder improvement program

PB reviewed Ergon Energy's feeder improvement program documentation and found the process adopted by Ergon Energy to identify the worst-performing feeders demonstrates a targeted approach.[1646] However, PB stated the documentation fails to demonstrate why the top 50 worst performing feeders is the prudent number to target.[1647] PB also found that the basis for the proposed cost per feeder and the scope of work associated with this cost is not considered in reaching the recommendation to proceed with the proposed program.[1648]

PB noted that the feeder improvement program documentation contains a summary of the performance but does not include a detailed analysis of the cause of poor performance of the worst performing feeders.[1649] Further, it does not consider how the feeder improvement program will integrate with the network operation improvements, preventive maintenance, augmentation and refurbishment capex, or the SCADA acceleration strategy. PB considered that while the feeder improvement program documentation recognises that benefits will be achieved from all these initiatives, it does not address the potential overlap in the proposed expenditures.[1650]

PB's concerns in relation to the proposed expenditure are:[1651]

- the individual benefits of each feeder improvement are not recognised or the timeframe over which they should be addressed is not listed
- the causes of poor performance are not recognised, and it is therefore unclear how the proposed expenditure will address the performance issues and how the proposed cost has been determined
- other capex and opex expenditures are identified that will also target the same performance problem, and this has not been taken into account in the development of the feeder improvement program capex proposal.

On the basis of the information presented, PB considered that Ergon Energy's proposed feeder improvement program capex would be best described as a provision for feeder improvement works rather than a program of specific projects.[1652] Due to the lack of supporting information, PB was unable to conclude that the proposed feeder improvement program capex is efficient.[1653]

[1645] As set out in its feeder improvement program, Ergon Energy ranks its feeders according to their actual average SAIDI performance and assigned a colour (red, amber, yellow and green). Red feeders have a SAIDI > 200 per cent of the MSS.
[1646] PB, *Report – Ergon Energy*, October 2009, p. 59.
[1647] PB, *Report – Ergon Energy*, October 2009, p. 59.
[1648] PB, *Report – Ergon Energy*, October 2009, p. 59.
[1649] PB, *Report – Ergon Energy*, October 2009, p. 59.
[1650] PB, *Report – Ergon Energy*, October 2009, p. 59.
[1651] PB, *Report – Ergon Energy*, October 2009, pp. 59–60.
[1652] PB, *Report – Ergon Energy*, October 2009, p. 60.
[1653] PB, *Report – Ergon Energy*, October 2009, p. 60.

SCADA installation

PB reviewed Ergon Energy's SCADA acceleration strategy and found that it includes a cost–benefit analysis. PB noted that this analysis demonstrates a positive NPV for this project, and shows that Ergon Energy's savings (excluding overheads) are estimated to be $56 million, while total cost savings by customers are estimated to be $213 million over the 15 year life of the project. (PB stated that the strategy document does not indicate the cost base for these figures).[1654]

PB also noted that the cost benefit analysis in the SCADA acceleration strategy is completely based on the estimated customer minutes savings for the three feeder categories (urban, short rural and long rural) due to the deployment of full SCADA to zone substations. PB noted the cost–benefit analysis demonstrated modest savings in operating costs for Ergon Energy, with these savings accruing only as the strategy is fully implemented.[1655] However, significant benefits are expected to accrue to customers based on the value of customer reliability (VCR) figures in the AER's service target performance incentive scheme (STPIS).[1656]

PB reviewed the documentation provided for the proposed SCADA acceleration strategy and is satisfied that it demonstrates the prudence and efficiency of the proposed expenditure.[1657]

Summary

PB concluded that while it accepts that it is prudent to forecast targeted expenditure in order to achieve reliability and quality standards, Ergon Energy's documentation does not clearly demonstrate this. PB found that the feeder improvement program documentation did not demonstrate efficient expenditure.[1658] PB concluded that the feeder improvement program, which represents 33 per cent of this capex category, is not specifically targeted expenditure but appears to be a provision to address feeder performance.[1659] PB considered that this is strictly not an issue of efficiency. However, it considered this a concern due to the potential for the proposed capex to duplicate other capex and opex that are identified to target the same performance problems.[1660] PB noted that the SCADA acceleration strategy documents did provide appropriate analysis and evidence of the costs and benefits.[1661]

PB stated that due to these concerns, as well as the limited application of economic analysis to support this forecast expenditure, it is unable to conclude that the proposed reliability and quality improvement capex is prudent or efficient.[1662]

PB recommended that expenditure for reliability and quality of supply be maintained at current period levels into the next regulatory control period, with the addition of an

[1654] PB, *Report – Ergon Energy*, October 2009, p. 60.
[1655] PB, *Report – Ergon Energy*, October 2009, p. 60.
[1656] PB, *Report – Ergon Energy*, October 2009, p. 60.
[1657] PB, *Report – Ergon Energy*, October 2009, p. 61.
[1658] PB, *Report – Ergon Energy*, October 2009, p. 61.
[1659] PB, *Report – Ergon Energy*, October 2009, p. 61.
[1660] PB, *Report – Ergon Energy*, October 2009, p. 61.
[1661] PB, *Report – Ergon Energy*, October 2009, p. 61.
[1662] PB, *Report – Ergon Energy*, October 2009, p. 61.

allowance for the proposed SCADA acceleration strategy.[1663] PB did not undertake a review of the prudence and efficiency of historical costs. However, PB stated its analysis did not reveal any reason or factors to indicate that reliability and quality improvement capex forecasts should significantly differ from current period expenditure (with the exception of the SCADA acceleration strategy). PB recommended a reduction in capex for reliability and quality improvement of $35 million in total over the next regulatory control period.[1664]

AER considerations

The AER notes Ergon Energy forecast an amount of $122 million ($2009–10) for reliability and quality improvement capex during the next regulatory control period, an increase of 131 per cent (in real terms) compared to the current regulatory control period. Reliability and quality improvement capex accounts for approximately 2 per cent of Ergon Energy's total proposed capex.

Ergon Energy stated that its reliability and quality capex is aimed at meeting internally and externally set MSS as specified in the Queensland EIC.[1665] The EIC states that a DNSP must use its best endeavours not to exceed the System Average Interruption Duration Index (SAIDI) limits and the System Average Interruption Frequency Index (SAIFI) limits applicable to its feeder types as set out in schedule 1 of the EIC.[1666]

In April 2009, the QCA made its final decision on the MSS to apply to Ergon Energy for the next regulatory control period.[1667] The AER notes the reliability targets to apply in the next regulatory control period are progressively more difficult to achieve and it is reasonable that Ergon Energy be provided with an allowance to target reliability and quality improvement. However, the onus is on Ergon Energy to satisfy the AER that its forecast capex is both prudent and efficient.

The AER has reviewed the documentation provided by Ergon Energy in support of its proposed reliability and quality capex. The AER notes PB's conclusion that Ergon Energy has established prudent strategies to identify the worst performing parts of its network and target expenditure on those areas. PB also considered that Ergon Energy's policies and procedures that relate to the management of reliability and quality improvement are generally consistent with good electricity industry practice.[1668] The AER accepts PB advice that the documentation is consistent with good electricity industry practice.

The AER notes PB concluded that the SCADA acceleration program is prudent and efficient.[1669] The AER reviewed the SCADA acceleration program documentation and notes that it includes cost benefit analysis setting out the benefits that will accrue

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1663 PB, *Report – Ergon Energy*, October 2009, p. 61.
1664 PB, *Report – Ergon Energy*, October 2009, p. 61.
1665 Ergon Energy, *Regulatory proposal*, July 2009, p. 209.
1666 Queensland Government, Department of Mines and Energy, *Electricity Industry Code*, Fourth edition, effective 4 August 2008, p. 17.
1667 QCA, *Review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010 – Final decision*, April 2009.
1668 PB, *Report – Ergon Energy*, October 2009, p. 61.
1669 PB, *Report – Ergon Energy*, October 2009, p. 60.

to both Ergon Energy and its customers.[1670] Benefits to customers are expected based on the value of customer reliability figures set out in the STPIS.[1671] The AER considers the SCADA acceleration program is prudent and efficient.

The AER notes PB's concerns in relation to the feeder improvement program, specifically that:[1672]

- the individual benefits of each feeder improvement are not recognised or the timeframe over which they should be addressed is not listed
- the causes of poor performance are not recognised, and it is therefore unclear how the proposed expenditure will address the performance issues and how the proposed cost has been determined
- other capex and opex expenditures are identified that will also target the same performance problem, and this has not been taken into account in the development of the feeder improvement program capex proposal.

Due to the lack of supporting information, PB was unable to conclude that the feeder improvement program is efficient. The AER has reviewed the feeder improvement program documentation and considers that there is insufficient information to support the program.

PB conducted a detailed review of 61 per cent of Ergon Energy's proposed reliability and quality capex for the next regulatory control period. While PB considered there was sufficient analysis to support the SCADA acceleration program, it was unable to support the feeder improvement capex which represents 33 per cent of this capex category. It recommended that forecast reliability and quality capex be maintained at current period levels and an allowance for the SCADA acceleration program be added.[1673] Reliability and quality capex in the current regulatory control period averages approximately $11 million per annum and the addition of forecast SCADA acceleration program results in a forecast amount of $87 million ($2009–10). The AER considers that PB's recommended approach to calculation of a substitute reliability and quality capex allowance is reasonable. The AER requested Ergon Energy model the impact of the AER's decision on reliability and quality capex. Ergon Energy advised that the adjustment to reliability and quality capex is a reduction of $35 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast reliability and quality capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed reliability and quality capex by $35 million[1674] results in expenditure that reasonably reflects the capex criteria, including the capex objectives,

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[1670] Ergon Energy, *Regulatory proposal*, July 2009, SCADA Acceleration Strategy, 1 April 2009.
[1671] Ergon Energy, *Email to AER*, 20 August 2009.
[1672] PB, *Report – Ergon Energy*, October 2009, pp. 59–60.
[1673] PB, *Report – Ergon Energy*, October 2009, p. 61.
[1674] See table G.19 for the treatment of the shared cost component of this deduction

and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

G.5.4.4 Other system capex

Ergon Energy regulatory proposal

Ergon Energy forecast an amount of $331 million ($2009–10) for other system capex during the next regulatory control period, an increase of 75 per cent (in real terms) compared to the current regulatory control period. Forecast other system capex represents approximately 5 per cent of Ergon Energy's total forecast capex program. Table G.11 sets out Ergon Energy's proposed other system capex for each year of the next regulatory control period.

Table G.11: Ergon Energy's proposed other system capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Other system	105.6	72.9	50.8	50.4	51.7	331.4

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 212.

Ergon Energy's other system capex is split into the following five categories:

- communications
- undergrounding
- single wire earth return
- protection
- other programs including low voltage fuse retrofits, low voltage spreaders, substation security, oil containment bunding and alternate substation alternating current supplies.

Communications

Ergon Energy stated that it has developed a communications network augmentation plan to connect the communications systems between the six regions of its network. It will also fill the missing links in its communications system between the medium sized centres with bulk supply connection and populations greater than 5000 people.[1675]

Ergon Energy stated that it will commence stage 1 of its telecommunications project, which will create a contiguous telecommunications backbone network, known as the 'Ubiquitous Network' (or UbiNet) in the current regulatory control period. Capex for stage 1 of UbiNet will continue into 2011–12.[1676] No forecast capex allowance has been included for stage 2 of UbiNet for the next regulatory control period.

[1675] Ergon Energy, *Regulatory proposal*, July 2009, p. 213.
[1676] Ergon Energy, *Regulatory proposal*, July 2009, p. 213.

Table G.12 sets out Ergon Energy's proposed other system communications capex for each year of the next regulatory control period. Communications capex represents 35 per cent of total other system capex for the next regulatory control period.

Table G.12: Ergon Energy's proposed system communications capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Communications	67.5	30.3	4.7	5.0	7.4	114.9

Source: Ergon Energy, email to AER, 24 September 2009.

Undergrounding

Ergon Energy stated that its forecast capex for undergrounding is built on a series of programs currently underway.[1677] Undergrounding is used in urban residential developments, where there is limited availability for overhead routes, to provide increased reliability in cyclone prone areas and where community and customers contribute to the costs of undergrounding.[1678]

The cyclone area reliability enhancement program (CARE) was instigated in coastal areas north of Mackay following two category 1 and 2 cyclones which caused widespread damage to the low voltage distribution network. The program aims to provide a more secure supply to essential services, improve security to high voltage feeders, retrofit fuses to distribution transformers and install line spreaders. Following Cyclone Larry in 2006 the program was expanded and annual expenditure was increased to $10 million per annum.[1679]

The community powerline project fund is funded equally by Ergon Energy and local government and aims to assist with community improvement programs. Ergon Energy contributes $2 million per annum to the program.

The Toowoomba trees program aims to reduce the impact of powerline infrastructure on vegetation in Toowoomba and is expected to cost $12 million in total. The program commenced in 2009–10 and will extend into the next regulatory control period.[1680]

Table G.13 sets out Ergon Energy's proposed other system undergrounding capex for each year of the next regulatory control period. Undergrounding capex represents 17 per cent of total other system capex for the next regulatory control period.

Table G.13: Ergon Energy's proposed undergrounding capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Undergrounding	11.0	11.4	11.4	11.3	10.1	55.3

Source: Ergon Energy, email to AER, 24 September 2009, confidential.

[1677] Ergon Energy, *Regulatory proposal*, July 2009, p. 220.
[1678] Ergon Energy, *Regulatory proposal*, July 2009, p. 220.
[1679] Ergon Energy, *Regulatory proposal*, July 2009, p. 220.
[1680] Ergon Energy, *Regulatory proposal*, July 2009, p. 221.

Single wire earth return

Ergon Energy stated that it operates a SWER network which comprises approximately 73 per cent of its total line lengths for long rural feeders and approximately 15 per cent of it total line lengths for short rural feeders. The SWER network distributes single phase power to more than 26 000 or four per cent of its customers. It stated that SWER capex relates to augmentation of its SWER network to meet customer capacity, reliability and quality of supply needs.[1681]

Ergon Energy stated that its forecast capex for the SWER program was a direct response to the 2004 EDSD Review which highlighted the need to improve reliability and quality of supply in areas serviced by SWER lines.[1682] The SWER plan includes trials of new technologies with the aim of implementing lower cost alternatives to traditional infrastructure.[1683]

Ergon Energy stated that it assumes that the Queensland government will continue to require it to focus on SWER improvements as recommended by the EDSD Review.[1684]

Table G.14 sets out Ergon Energy's proposed other system SWER protection capex for each year of the next regulatory control period. SWER capex represents 20 per cent of total other system capex for the next regulatory control period.

Table G.14: Ergon Energy's proposed SWER capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
SWER	12.1	12.8	13.5	13.6	14.2	66.2

Source: Ergon Energy, email to AER, 24 September 2009, confidential.

Protection

Ergon Energy stated that it has developed a network protection and control program which includes retrofitting autoreclose protection and sensitive earth fault protection on existing feeders as well as undertaking protection reviews.[1685] Other aspects of the program are forecast as part of asset replacement and reliability and quality improvement capex.

The autoreclose program is aimed at reducing outages, resulting in improvement to SAIDI and SAIFI and reducing costs associated with outages. Ergon Energy stated that it will fit autoreclose protection to 73 of its feeders which currently do not have this capability.[1686]

The sensitive earth fault protection program aims to retrofit sensitive earth fault protection to 210 feeders and is designed to reduce public safety risks which occur

[1681] Ergon Energy, *Regulatory proposal*, July 2009, p. 213.
[1682] Ergon Energy, *Regulatory proposal*, July 2009, p. 220.
[1683] Ergon Energy, *Regulatory proposal*, July 2009, p. 220.
[1684] Ergon Energy, *Regulatory proposal*, July 2009, p. 219.
[1685] Ergon Energy, *Regulatory proposal*, July 2009, p. 215.
[1686] Ergon Energy, *Regulatory proposal*, July 2009, p. 215.

when conductors fall to the ground and the fault current is too low to de–energise the circuit.[1687]

Ergon Energy noted that its network protection and control program is dependant on the asset replacement program. A reduction in asset replacement expenditure may result in some protection programs taking longer to complete.[1688]

Table G.15 sets out Ergon Energy's proposed other system protection capex for each year of the next regulatory control period. Protection capex represents 14 per cent of total other system capex for the next regulatory control period.

Table G.15: Ergon Energy's proposed system protection capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Protection	6.0	8.5	10.2	9.9	10.5	45.1

Source: Ergon Energy, email to AER, 24 September 2009, confidential.

Other programs

Ergon Energy has proposed capex for other programs including:[1689]

- a substation security program to minimise risks and align its substations with the Code of Practice
- complete the low voltage fuse retrofit program on transformers commenced under the CARE program
- substation bunding programs to meet environmental requirements
- improve substation reliability by securing alternating current supplies
- complete the installation of low voltage spreaders on small low voltage conductors. This work was commenced under the CARE program and expanded to other areas to reduce supply interruptions due to conductor clashing due to high winds and vegetation.

Table G.16 sets out Ergon Energy's proposed other programs capex for each year of the next regulatory control period. Other programs capex represents 15 per cent of total other system capex for the next regulatory control period.

Table G.16: Ergon Energy's proposed other programs capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Other programs	9.1	10.0	10.9	10.7	9.4	49.9

Source: Ergon Energy, email to AER, 24 September 2009.

[1687] Ergon Energy, *Regulatory proposal*, July 2009, p. 220.
[1688] Ergon Energy, *Regulatory proposal*, July 2009, p. 219.
[1689] Ergon Energy, *Regulatory proposal*, July 2009, p. 221.

Consultant review

PB noted that Ergon Energy proposed $331 million for other system capex in the next regulatory control period. This represents a real increase of 75 per cent compared to the current regulatory control period.[1690] PB undertook a high level review of Ergon Energy's other system capex and has examined in detail those expenditure categories which constitute a high proportion of overall proposed capex. PB noted that 58 per cent of expenditure in this category relates to communications and undergrounding. PB also noted that the largest elements are the UbiNet project (communications) and the CARE program (undergrounding). Consequently, PB concentrated its review on these two capex items. PB stated that if UbiNet were excluded from the expenditure proposal, the proposed other system capex category would reduce to virtually a business as usual approach.[1691]

PB noted that in assessing the prudence and efficiency of proposed capex, it has considered the need or driver, as well as the timing of the expenditure and where appropriate, used a business as usual level of expenditure to develop a view about the appropriate level of forecast capex. PB stated that given Ergon Energy is incentivised to be efficient by the CPI–X form of regulation, PB considers that business as usual levels of capex can be considered as indicative of efficient capex.[1692] PB noted that a business as usual approach may differ from historical expenditures in so far as historical expenditures may include abnormal under and over spends.[1693]

Communications

PB stated that forecast communications capex represents 38 per cent of the proposed total other system capex, and relates to the proposed UbiNet project.[1694]

Ergon Energy has commenced the first stage of its UbiNet project which will satisfy a range of telecommunications functions. Stage one involves investing in the core telecommunications backbone network and is expected to be completed by 2011–12. No further UbiNet capex is proposed for the next regulatory control period.[1695]

PB noted that the UbiNet business case was reviewed by both the Queensland Treasury Corporation (QTC) and Evans and Peck.[1696] PB found that the business case for UbiNet was limited, in that it only considered two options: business as usual and establishing UbiNet. PB also found that QTC's financial model and high level business case review identified that a relatively large amount of the projects opex and capex is based on internally sourced estimates rather than estimates sourced from expert third parties.[1697] Further QTC noted that on an NPV basis the project benefits

[1690] PB, *Report – Ergon Energy*, October 2009, p. 62.
[1691] PB, *Report – Ergon Energy*, October 2009, p. 63.
[1692] PB, *Report – Ergon Energy*, October 2009, p. 4.
[1693] PB, *Report – Ergon Energy*, October 2009, p. 4.
[1694] PB, *Report – Ergon Energy*, October 2009, p. 63.
[1695] PB, *Report – Ergon Energy*, October 2009, p. 63.
[1696] PB, *Report – Ergon Energy*, October 2009, p. 63.
[1697] PB, *Report – Ergon Energy*, October 2009, pp. 63–64.

were not significant and an increase in costs would make it more beneficial to pursue a business as usual approach.[1698]

Ergon Energy engaged Evans and Peck to undertake an independent review of the UbiNet business case and assess whether the estimated costs presented align with telecommunication industry expectations for a network of this size. Evans and Peck confirmed that the estimated capital costs were reasonable for a project of Ergon Energy's size and geographic spread.[1699]

PB agreed with QTC's view that the business case for UbiNet is marginal, and any increase in the estimated costs would make this expenditure inefficient.[1700] However, PB acknowledged that based on current cost estimates Ergon Energy's business case demonstrates that UbiNet is an economically justified investment and therefore the proposed expenditure can be considered prudent and efficient.[1701] PB stated that Ergon Energy will need to manage the costs, risks and benefits of this project closely to ensure that the value on which the business case is based is achieved.[1702]

Undergrounding

PB stated that Ergon Energy's proposed undergrounding capex represents 20 per cent of the proposed total other system capex. This capex refers to specific undergrounding in relation to the CARE program and the Toowoomba Trees program. The majority of forecast undergrounding capex is associated with the CARE program.[1703]

PB noted that the CARE program involves the progressive undergrounding of critical high voltage infrastructure in cyclone prone areas. PB also noted that while the CARE expenditure is not mandatory, it has the support of local government and communities and aims to limit the impact of cyclones on the community and Ergon Energy's distribution network.[1704] Given the relative size of the expenditure, and the likely community and network benefits, PB stated that this expenditure is prudent.[1705]

PB has also examined Ergon Energy's underground cabling strategy and noted that the primary focus of the CARE program has been the undergrounding of high voltage backbone lines and not all aspects of the original CARE program have been achieved.[1706] Following its review of the underground cabling strategy PB found that the management of the CARE program is prudent. However, it noted that the value achieved from the proposed expenditure is diminishing, and the value, effectiveness and efficiency are likely to have changed since the inception of the program. PB noted that the strategy should be reviewed.[1707]

[1698] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1699] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1700] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1701] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1702] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1703] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1704] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1705] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1706] PB, *Report – Ergon Energy*, October 2009, pp. 64–65.
[1707] PB, *Report – Ergon Energy*, October 2009, p. 65.

PB concluded that as a result of its review of forecast undergrounding capex the proposed expenditure is generally in accordance with a business as usual approach (that is, historical expenditure with abnormal under and over spends removed) and it has not recommended any adjustments.[1708]

Overview

PB noted that the real increase of 75 per cent in the other capex category over the current period is almost completely attributable to the one-off UbiNet project, which PB concluded is prudent and efficient. The balance of the expenditure in this category (once UbiNet is removed) is generally in accord with historical levels of expenditure, and appears to represent a business as usual approach.[1709]

Based on its high level review, PB concluded that proposed capex was prudent and efficient and did not consider a more detailed review was required. It recommended that Ergon Energy's proposed other capex be accepted.[1710]

AER considerations

The AER has considered PB's detailed review and recommendations on the categories of other system capex as well as the documentation provided by Ergon Energy. The AER's considerations on each category of other system capex are set out below.

Communications

Communications is the largest category of other system capex and relates to the UbiNet project. Stage one of the UbiNet project is expected to span 2008–09 to 2011–12 and will focus on developing the core network. Future network augmentation will only need to fund communication assets required in the lower voltage sections of the network.

During its review, PB noted that the QTC had reviewed the UbiNet business case and concluded that the benefits were marginal and a 10 per cent increase in capital costs would make it uneconomical to proceed.[1711] Evans and Peck also reviewed the business case and concluded the estimated capital costs were in line with a project of UbiNet's size and geographical spread. PB agreed with QTC's view that the project was marginal and a change to estimated costs would make the capex inefficient. However, based on current cost estimates, the UbiNet project is an economically justified investment and therefore can be considered prudent and efficient.

The AER notes the comments made by PB in relation to the financial benefits of pursuing the UbiNet project and its sensitivity to capital costs. QTC also stated that there are strategic considerations and other qualitative factors that better align the likely outcomes achieved from the UbiNet implementation with the strategic direction of Ergon Energy.[1712] Further, Evans and Peck noted that in developing the UbiNet

[1708] PB, *Report – Ergon Energy*, October 2009, p. 66.
[1709] PB, *Report – Ergon Energy*, October 2009, p. 66.
[1710] PB, *Report – Ergon Energy*, October 2009, p. 66.
[1711] PB, *Report – Ergon Energy*, October 2009, p. 64.
[1712] QTC, Letter to Ergon Energy: UbiNet project – Finacial model and high level business case review, confidential, 14 May 2008, p. 5.

business case, Ergon Energy has followed a rigorous process considering current and future telecommunications requirements and international trends.[1713]

On reviewing the documentation provided and the analysis of PB, the AER considers the UbiNet project is, at this stage, economically justified. It has the support of the QTC as well as Evans and Peck, and will assist Ergon Energy to follow its strategic direction. The AER also notes that the project has commenced in the current regulatory control period. The AER considers that the proposed expenditure is prudent and efficient.

Undergrounding

Undergrounding capex comprises approximately 17 per cent of other system capex and is mostly targeted at the CARE program.

The AER notes PB's comments on the possible declining value of the CARE program. Ergon Energy stated that guidelines provided for the undergrounding of the high voltage backbone were aimed at establishing secure underground connections to essential services such as hospitals, schools and water and sewerage pumps as a priority.[1714] It indicated that the number of high priority installations is becoming exhausted and it is now time to commence the second stage of CARE projects with different criteria to spread the program to a wider range of customers.[1715] Therefore, while the value may be declining, the CARE program is still likely to provide benefits to customers via increased network reliability.

In relation to the Toowoomba Trees program, the AER notes that in late 2008, the Ergon Energy Board resolved to endorse the allocation of funds to address the impact of powerline infrastructure on existing infrastructure in Toowoomba.[1716] Ergon Energy considered that the tree lined streets were an emblematic symbol of Toowoomba and therefore it was important to treat the city as a special case.[1717]

The AER has reviewed the information provided by Ergon Energy in support of its proposed undergrounding capex and considers the programs and strategy are likely to provide community and customer benefits. The AER considers the continuation of the CARE and Toowoomba Trees programs is prudent given the likely benefits in terms of improved network reliability and additional community and customer benefits. Further, the AER accepts PB's advice that the proposed capex is prudent and efficient and that no changes be made to Ergon Energy's forecast undergrounding capex.

[1713] Evans and Peck, *Ergon Energy: UbiNet – Review of business case, Report V3*, confidential, 10 November 2008, p. 3.

[1714] Ergon Energy, *Regulatory proposal*, July 2009, AR450, Underground cabling strategy, 31 March 2009, p. 29.

[1715] Ergon Energy, *Regulatory proposal*, July 2009, AR450, Underground cabling strategy, 31 March 2009, p. 32.

[1716] Ergon Energy, *Regulatory proposal*, July 2009, AR245c, EE Board Paper 0713–13 Toowoomba Trees Program Resolution, confidential, 22 December 2008.

[1717] Ergon Energy, *Regulatory proposal*, July 2009, AR245c, EE Board Paper 0713–13 Toowoomba Trees Program Resolution, confidential, 22 December 2008.

Single wire earth return

Ergon Energy stated that its proposed SWER capex relates to augmentation of its SWER network to meet customer capacity, reliability and quality of supply needs and was a direct response to the EDSD Review. Ergon Energy's SWER program accounts for approximately 1 per cent of total forecast capex for the next regulatory control period.

Ergon Energy provided the AER with information setting out its assessment of the current state and proposed improvements to its SWER network. The information included analysis of its network which indicated areas where the network is currently constrained and where it was likely to be constrained in the future.[1718] The AER considers that based on the information provided, Ergon Energy has developed a plan to improve its SWER network as required by the EDSD Review. Ergon Energy's proposed SWER capex will assist it to achieve the outcomes specified in its plan. The AER considers Ergon Energy's proposed SWER capex to be prudent. While the AER has not conducted a detailed review of the efficiency of Ergon Energy's proposed SWER capex it notes that it is consistent with its historical expenditure on this category. Further, the AER notes that based on its high level review, PB did not recommend any adjustments to proposed SWER capex, concluding that it was prudent and efficient. The AER accepts PB's advice and has not made adjustments to proposed SWER capex.

Protection

Ergon Energy stated that its network protection program includes retrofitting autoreclose protection and sensitive earth fault (SEF) protection on existing feeders as well as undertaking protection reviews.[1719] Ergon Energy's proposed protection program capex accounts for less than 1 per cent of total forecast capex for the next regulatory control period.

Ergon Energy stated that 1033 of its feeders are already equipped with autoreclose capability and fitting autoreclose to the remaining 73 feeders will improve reliability on its network.[1720] Based on the information provided, Ergon Energy has developed a strategy for identifying feeders without autoreclose capability and prioritised its program based on the contribution to SAIDI of those affected feeders. It has also aligned its proposed program with other protection programs such as the SEF program and SCADA programs to optimise efficiency.[1721]

Ergon Energy noted that 80 per cent of its feeders are equipped with SEF protection which detects high impendence earth faults. It proposed to fit SEF to the remaining 210 feeders over the next regulatory control period. The SEF program will assist Ergon Energy mitigate public safety risks associated with fallen high voltage

[1718] Ergon Energy, *Regulatory proposal*, July 2009, AR413c EE Current state assessment distribution and SWER 2008.xls, confidential.

[1719] Ergon Energy, *Regulatory proposal*, July 2009, p. 215.

[1720] Ergon Energy, *Regulatory proposal*, July 2009, AR463c EE Auto–reclose program v2, February 2008, p. 1.

[1721] Ergon Energy, *Regulatory proposal*, July 2009, AR463c EE Auto–reclose program v2, February 2008, p. 1.

overhead conductors on multiphase feeders.[1722] Ergon Energy has developed a strategy for identifying feeders without SEF protection and prioritised its program based on feeder location and therefore public risk as well as the number of customers affected. It has also aligned its proposed program with other protection programs such as the feeder autoreclose program and SCADA programs to optimise efficiency.

The AER considers the feeder autoreclose program will provide benefits in terms of increased reliability on Ergon Energy's network. The SEF program is likely to improve public safety particularly during and after storms when overhead power lines are likely to fall. Therefore the AER considers Ergon Energy's proposed protection capex is prudent. The AER notes that Ergon Energy has developed costs for the feeder autoreclose and SEF programs and while it has not conducted a detailed assessment of the overall efficiency of these programs it does note that protection and control programs have been aligned to promote efficiency. Further proposed expenditure is generally consistent with historical expenditure. The AER notes that based on its high level review, PB did not recommend any adjustments to proposed protection capex and that it was prudent and efficient. The AER accepts PB's advice and has not made adjustments to proposed protection capex.

Other programs

The other programs category includes a number of smaller projects involving substation security, retro fitting low voltage fuses, substation bunding works, improving the reliability of substation alternating current supplies and fitting low voltage spreaders to lines to prevent conductor clashing. The AER notes that the retrofitting of low voltage fuses to distribution transformers and the fitting of low voltage spreaders to lines commenced as part of the CARE program and it is prudent to complete these programs particularly given they will enhance network safety. Given the number of relatively minor projects and the immaterial impact on proposed total capex (less than 1 per cent of total proposed capex), the AER has not conducted a detailed review of other programs.

The AER notes that as a result of its high level review, PB did not recommend any adjustments to this category of proposed capex.[1723] The AER accepts PB's advice and has not made an adjustment to the other programs category of other system capex.

Summary

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is satisfied that Ergon Energy's forecast other system capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

[1722] Ergon Energy, *Regulatory proposal*, July 2009, AR463c_EE_Protection & Control sensitive earth fault protection program, February 2008, confidential, p. 1.

[1723] PB, *Report – Ergon Energy*, October 2009, p. 66.

G.5.4.5 Non–system capex

Ergon Energy regulatory proposal

Ergon Energy's proposed non–system capex of $679 million ($2009–10) includes expenditure on ICT systems, motor vehicles, property (buildings, land, easements, office equipment and furniture), and tools and equipment. Non–system capex represents approximately 11 per cent of the total forecast capex program. Table G.17 sets out Ergon Energy's proposed non–system capex by major categories.

Table G.17: Ergon Energy's proposed non–system capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ICT systems	20.3	18.9	18.2	17.1	18.4	92.9
Motor vehicles	30.9	30.3	32.0	32.3	35.0	160.5
Property	122.2	142.2	77.1	24.9	20.4	386.8
Tools and equipment	7.5	7.6	7.8	7.9	8.0	38.8
Total	180.9	199.0	135.2	82.3	81.7	679.1

Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
Note: Totals may not add due to rounding.

Ergon Energy's non–system assets capex forecast to increase by $24 million ($2009–10) or 4 per cent compared to the current regulatory control period. Proposed non–system capex in the next regulatory control period is greater than expenditure in the current regulatory control period for property, steady for motor vehicles, and lower for ICT systems and tools and equipment.[1724]

ICT systems

Ergon Energy proposed to spend $93 million on ICT systems during the next regulatory control period, a decrease of 46 per cent from the current regulatory control period. Forecast expenditure includes costs associated with the replacement and upgrade of ICT systems and infrastructure such as desktop and laptop personal computers, smaller ICT devices and other legacy assets owned by Ergon Energy.[1725]

The majority of Ergon Energy's total expenditure on information and communications technology is incorporated in Ergon Energy's arrangements with SPARQ Solutions, which are discussed as part of Ergon Energy's overheads in section G.5.5 of this appendix. The falling expenditure in this category reflects the fact that Ergon Energy's reliance on ICT assets held in its own right rather than by SPARQ Solutions is decreasing.[1726]

[1724] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1
[1725] Ergon Energy, *Regulatory proposal*, July 2009, p. 226.
[1726] Ergon Energy, *Regulatory proposal*, July 2009, p. 227.

Motor vehicles

Ergon Energy proposed to spend $161 million on motor vehicles in the next regulatory control period. This is in line with expenditures in this category in the current regulatory control period.

Office equipment and furniture

Ergon Energy proposed to spend $3 million on office furniture and equipment in the next regulatory control period. This is 77 per cent lower than reported expenditures in this category in the current regulatory control period, though these figures are not directly comparable. The forecast capex for office equipment and furniture relates only to assets required for existing offices and depots, whereas actual expenditure reported in this category for the current regulatory control period also includes expenditure relating to the fit out of new buildings. Forecast expenditure in this category is assumed to be at the same level as in 2009–10 throughout the next regulatory control period.[1727]

Property

Ergon Energy's proposed capex for non–system buildings, land and easements amounts to $384 million during the next regulatory control period. Ergon Energy also proposed to spend $2.6 million on office furniture and equipment in the next regulatory control period. In total, Ergon Energy proposed property related capex of $387 million, an increase of approximately 74 per cent from the current regulatory control period. The key proposed investments include:

- construction of a new depot and additional office accommodation in Townsville
- consolidation of all Cairns operations at a new site
- redevelopment of the Rockhampton Glenmore Road site
- redevelopment of the main operational depot in Maryborough
- construction of a new office building and other works in Toowoomba
- establishment of a data centre.[1728]

Ergon Energy's proposed expenditure in this category relates to the implementation of its *Corporate Property Strategic Plan* developed in 2006. The key drivers of the *Corporate Property Strategic Plan* are the implementation of a Hub and Spoke model (consolidating all administrative work at hubs and large spokes), the consolidation of sites where possible, and the assumed continuation of existing business functions.[1729]

Tools and equipment

Ergon Energy proposed capex of $39 million on tools and equipment in the next regulatory control period. This represents a decrease of 59 per cent from the current regulatory control period. Forecast expenditure is based on expenditure in 2007–08,

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[1727] Ergon Energy, *Regulatory proposal*, July 2009, p. 235.
[1728] Ergon Energy, *Regulatory proposal*, July 2009, pp. 232–233.
[1729] Ergon Energy, *Regulatory proposal*, July 2009, p. 230.

reduced to reflect Ergon Energy's assessment that expenditure in that year was higher than a typical year. Expenditure in this category includes purchases of tools and equipment valued at greater than $1000.[1730]

Consultant review

PB reviewed Ergon Energy's proposed non–system capex for the next regulatory control period. Its review encompassed a high level analysis of trends in expenditures from the current and previous regulatory control periods, and a review of the specific expenditure categories proposed by Ergon Energy. The detailed review of proposed expenditure categories undertaken by PB included consideration of relevant policies and procedures and other expenditure drivers.[1731]

In summary, PB found that Ergon Energy's proposed non–system capex was not prudent and efficient and recommended a reduction of $256 million to Ergon Energy's proposed expenditure of $679 million.[1732] PB's findings on each category of Ergon Energy's proposed non–system capex are set out below.

ICT systems

PB reviewed Ergon Energy's total forecast ICT systems capex, including both the expenditure to be capitalised by Ergon Energy as well as the expenditure to be capitalised by SPARQ, which is reflected in SPARQ's service charge to Ergon Energy.[1733] The recommendations discussed in this section relate only to PB's review of Ergon Energy's proposed ICT systems capex, made up of items which Ergon Energy will continue to purchase in the next regulatory control period. These items include end use computing assets such as desktop and laptop personal computers and smaller ICT devices.[1734]

PB noted that Ergon Energy's Joint ICT Investment Plan sets out a blueprint to upgrade or replace existing ICT assets to meet operational needs, as well as to enhance and develop new capabilities. The operational role of the plan is to guide ICT investment decision making for the near to medium term, including through direct input to the annual consolidated program of work planning process.[1735] PB noted that, in general, ICT systems expenditure is driven by the discontinuation of older versions of software, business and technology changes, and the need to increase functional capabilities and performance or improve efficiency.[1736]

In reviewing Ergon Energy's proposed ICT systems capex, PB could not reconcile Ergon Energy's regulatory proposal with its bottom up ICT forecast, and sought clarification. Following the provision of further information by Ergon Energy, PB found that Ergon Energy had included an amount of $50 million ($10 million per annum) in direct costs associated with a 'Change Program' as well as other indirect

[1730] Ergon Energy, *Regulatory proposal*, July 2009, pp. 222–223.
[1731] PB, *Report – Ergon Energy*, October 2009, p. 69.
[1732] PB, *Report – Ergon Energy*, October 2009, p. 95.
[1733] PB, *Report – Ergon Energy*, October 2009, p. 72.
[1734] PB, *Report – Ergon Energy*, October 2009, p. 74.
[1735] PB, *Report – Ergon Energy*, October 2009, p. 75.
[1736] PB, *Report – Ergon Energy*, October 2009, pp. 74–75.

overhead costs amounting to $17 million as part of its total $93 million expenditure proposal.[1737]

PB considered that, at a minimum, a rationale or key elements of a capex business case (such as a net benefits appraisal) should be presented to demonstrate that expenditure proposed is both prudent and efficient. PB stated that Ergon Energy was unable to provide business case documents in support of the Change Program and associated overheads proposed. As no information was provided to demonstrate the prudence and efficiency of the Change Program, PB was not satisfied that additional expenditure above and beyond that directly relating to end use computing assets was justified.[1738]

On the basis of its review, PB found that Ergon Energy's proposed ICT systems capex was not prudent and efficient and considered that the proposed ICT capex should be adjusted to reflect costs directly relating to investment in end use computing assets only, excluding costs associated with the Change Program.[1739] PB recommended that Ergon Energy's proposed ICT systems capex be reduced by $65 million, being the direct costs associated with the Change Program ($50 million) and the related proportion of indirect costs included in the total proposed ICT systems capex.[1740]

Property

PB reviewed Ergon Energy's proposed property capex for the next regulatory control period. PB included the amount of $2.6 million proposed by Ergon Energy as office equipment and furniture for the purposes of its review of the proposed buildings, land and easements (property) capex.[1741]

PB noted that the majority of major building expenditure was proposed to occur in the first two years of the next regulatory control period. PB requested business case documentation or supporting documentation for six high value individual projects proposed by Ergon Energy, which together make up the majority of the proposed property capex. PB noted that Ergon Energy was unable to provide this documentation, including in relation to expenditure proposed for the first year of the next regulatory control period, as Ergon Energy intended to develop such documentation closer to project realisation.[1742]

PB noted that the proposed expenditure represents a significant increase from historical expenditure, and expressed concern about the magnitude of the proposed increase during the early years of the next regulatory control period. PB requested information on how building projects had been prioritised, but this was not provided.[1743]

[1737] PB, *Report – Ergon Energy*, October 2009, pp. 79–80.
[1738] PB, *Report – Ergon Energy*, October 2009, p. 80.
[1739] PB, *Report – Ergon Energy*, October 2009, p. 80.
[1740] PB, *Report – Ergon Energy*, October 2009, pp. 80–81.
[1741] PB, *Report – Ergon Energy*, October 2009, p. 82.
[1742] PB, *Report – Ergon Energy*, October 2009, p. 85.
[1743] PB, *Report – Ergon Energy*, October 2009, pp. 85–86.

In the course of its review, PB identified a number of concerns with the documentation provided by Ergon Energy in support of the proposed property capex, including:[1744]

- the buildings strategy was out of date and had not been updated to take into account recent changes affecting buildings
- the management options presented did not include sufficient detail to understand how the options were ranked
- data supporting the prioritisation of building works was not provided
- information provided was insufficient to support the deliverability of the increased workload and tight deadlines proposed.

On the basis of its review, PB concluded that Ergon Energy's property capex had not been demonstrated to be prudent and efficient, and recommended expenditure in line with Ergon Energy's business as usual costs. PB further recommended that the level of business as usual costs be set by removing the major building project expenditures found to be not prudent and efficient from the capex proposal. PB recommended a prudent and efficient level of property capex for Ergon Energy of $196 million over the next regulatory control period, representing a reduction of $191 million from Ergon Energy's proposal.[1745]

Motor vehicles

PB reviewed Ergon Energy's proposed motor vehicles capex, including three key inputs to the forecast: vehicle replacement policies, the quantity of vehicles in the fleet, and Ergon Energy's procurement processes.[1746]

PB noted that Ergon Energy's motor vehicle replacement policy is driven by age based replacement criteria depending on vehicle type, and verified Ergon Energy's adherence to the policy.[1747] PB concluded that Ergon Energy's procurement processes should result in efficient costs for fleet capex.[1748]

PB noted that, following a fleet benchmarking and modelling report prepared by UMS Group, Ergon Energy had adopted an extended four year replacement policy for light vehicles. PB analysed the cost of motor vehicle capex per employee over the current and next regulatory control periods, and found that costs were forecast to decrease by 8 per cent per employee in the next regulatory control period. PB noted that this outcome was consistent with UMS Group's findings and Ergon Energy's response to that review.[1749]

[1744] PB, *Report – Ergon Energy*, October 2009, pp. 86–87.
[1745] PB, *Report – Ergon Energy*, October 2009, pp. 87–88.
[1746] PB, *Report – Ergon Energy*, October 2009, p. 89.
[1747] PB, *Report – Ergon Energy*, October 2009, p. 89.
[1748] PB, *Report – Ergon Energy*, October 2009, p. 90.
[1749] PB, *Report – Ergon Energy*, October 2009, pp. 89–90.

On the basis of its review, PB concluded that Ergon Energy's proposed motor vehicles capex was prudent and efficient and therefore be accepted without adjustment.[1750]

Tools and equipment

PB undertook a high level review of Ergon Energy's proposed expenditure on tools and equipment.[1751] PB noted that the key driver for the proposed expenditure was ensuring that Ergon Energy employees have the tools and equipment to perform their work in a safe and efficient manner.[1752] PB found that the decrease in expenditure in this category in the next regulatory control period was due to greater expenditure on very expensive tool and equipment items in the current regulatory control period, together with productivity factor improvements proposed in the next regulatory control period.[1753]

As part of its review, PB considered the processes and procedures used to determine current and projected tooling and equipment levels. PB found that Ergon Energy had developed a number of tools and equipment standards to ensure fitness for purpose and best value for money. Ergon Energy's tools and equipment framework was found to contain relevant safety standards and procedures for the procurement, maintenance, testing and disposal of tools and equipment.[1754]

PB recommended that the proposed capex for tools and equipment be accepted without adjustment.[1755]

AER considerations

The AER has reviewed Ergon Energy's non–system capex proposal, taking into account additional information provided in support of the regulatory proposal and the advice of PB.

The AER notes that Ergon Energy's proposed non–system capex represents an increase of 4 per cent from the current regulatory control period. The AER also notes that while proposed non–system capex in the next regulatory control period is greater than expenditure in the current regulatory control period for property, it is lower for ICT systems and tools and equipment, and approximately steady for motor vehicles.[1756]

The AER notes PB's findings that the proposed expenditures for both tools and equipment and motor vehicles should be accepted without adjustment.[1757] The AER notes that expenditures in these categories are either below or consistent with historical expenditure.[1758] Having reviewed Ergon Energy's regulatory proposal and the policies and procedures underpinning these expenditures, the AER considers that

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[1750] PB, *Report – Ergon Energy*, October 2009, p. 91.
[1751] PB, *Report – Ergon Energy*, October 2009, p. 93.
[1752] PB, *Report – Ergon Energy*, October 2009, p. 92.
[1753] PB, *Report – Ergon Energy*, October 2009, p. 93.
[1754] PB, *Report – Ergon Energy*, October 2009, pp. 92–93.
[1755] PB, *Report – Ergon Energy*, October 2009, p. 93.
[1756] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
[1757] PB, *Report – Ergon Energy*, October 2009, p. 94.
[1758] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.

the proposed expenditures for plant and tools and motor vehicles represent the efficient costs of a prudent operator in Ergon Energy's circumstances.

In relation to Ergon Energy's proposed ICT systems capex, the AER notes that Ergon Energy was unable to provide business case documents in support of the Change Program and associated overheads. The AER notes PB's view that Ergon Energy's proposed ICT systems capex is not prudent and efficient and that the proposed ICT capex should be adjusted to reflect costs directly relating to investment in end–use computing assets only, excluding costs associated with the Change Program.[1759]

The AER has reviewed Ergon Energy's proposed ICT systems capex, and is not satisfied, on the basis of the information provided by Ergon Energy, that the capex associated with the Change Program are prudent and efficient expenditures. The AER therefore considers that costs associated with the Change Program should be excluded from Ergon Energy's proposed ICT systems capex. The AER requested Ergon Energy to model the impact of the AER's decision on ICT systems capex. Ergon Energy advised that the adjustment to forecast ICT systems capex is a reduction of $65 million ($2009–10).

The AER notes that Ergon Energy's proposed capex for non–system property (comprising expenditure on buildings, land, easements, office equipment and furniture) amounts to $387 million during the next regulatory control period, a significant increase of 74 per cent from the current regulatory control period.[1760] The AER received a submission from the EUAA noting the very significant expansion of expenditure by Ergon Energy on corporate property and requesting that the AER investigate this carefully to determine its purpose, relevance and benefit.[1761]

The AER notes that Ergon Energy was unable to provide business case documentation or other supporting documentation for the high value property projects proposed for Townsville, Cairns, Rockhampton, Toowoomba, Maryborough and the data centre, including in relation to expenditure proposed for the first year of the next regulatory control period.[1762]

The AER notes PB's finding that Ergon Energy's proposed property capex is not prudent and efficient, and that expenditure should be in line with Ergon Energy's business as usual costs, excluding the new proposed major building project expenditures.[1763]

The AER considers that Ergon Energy's proposal has not adequately demonstrated the prudence and efficiency of the program of proposed building works, for example through a clear exposition of the consideration of options, prioritisation of projects or cost–benefit analysis underpinning the proposed program. The AER therefore considers that the major building project expenditures proposed by Ergon Energy for Townsville, Cairns, Rockhampton, Toowoomba, Maryborough and the data centre have not been demonstrated to be prudent and efficient and should be removed from

[1759] PB, *Report – Ergon Energy*, October 2009, p. 80.
[1760] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
[1761] EUAA, *Submission to the AER*, August 2009, p. 21.
[1762] PB, *Report – Ergon Energy*, October 2009, p. 85.
[1763] PB, *Report – Ergon Energy*, October 2009, p. 87.

the capex proposal. The AER requested Ergon Energy to model the impact of the AER's decision on property capex. Ergon Energy advised that the adjustment to forecast property capex is a reduction of $188 million ($2009–10).

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's proposed non–system capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed non–system capex by $253 million[1764] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

G.5.5 Shared costs

This section examines whether Ergon Energy's shared costs, commonly referred to as overheads, are appropriate and are allocated in a manner that is likely to result in prudent and efficient investment for the delivery of standard control services. The AER considers that assessing shared costs in this manner is relevant for determining whether the AER is satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria.

Ergon Energy proposal

Ergon Energy stated that its forecast capex for the next regulatory control period includes shared costs that have been allocated on the basis of the cost allocation methodology approved by the AER.[1765]

Ergon Energy indicated that its cost allocation method outlines the principles it is to use to allocate its shared costs across the various business units and subsidiaries within the Ergon Energy group of companies.[1766]

Ergon Energy indicated that its shared costs arise from the following sources:[1767]

- office of the chief executive
- corporate governance
- finance and strategic services (including ICT services)
- employee and shared services
- customer and stakeholder engagement
- customer services.

[1764] See table G.19 for the treatment of the shared cost component of this deduction.
[1765] Ergon Energy, *Regulatory proposal*, July 2009, p. 192.
[1766] Ergon Energy, *Regulatory proposal*, July 2009, p. 136.
[1767] Ergon Energy, *Regulatory proposal*, July 2009, AR314, Ergon Energy cost allocation method, p. 9.

Ergon Energy stated that a large proportion of its shared costs is accounted for by the provision of ICT services provided by SPARQ, which is jointly owned by Energex and provides ICT services to both businesses.[1768] Services provided by SPARQ to Ergon Energy include:[1769]

- corporate ICT services, including help desk support
- ICT procurement of hardware and software
- voice and data telecommunication
- infrastructure services, including mainframe, corporate data, storage area network, Unix, Windows and email servers
- business application services used in the provision of distribution services.

Ergon Energy noted that it commissioned KPMG to perform a review of the prudency and efficiency of the ICT services delivered by SPARQ. Ergon Energy indicated that KPMG confirmed that SPARQ's expenditure forecasts are reasonable and can be relied upon for the purposes of forecasting Ergon Energy's shared costs attributable to SPARQ ICT services.[1770]

Consultant review

PB noted that Ergon Energy allocates shared costs as per the AER's approved cost allocation methodology, which results in 77 per cent of shared costs being allocated to capex and 23 per cent being allocated to opex.[1771]

In its review of Ergon Energy's proposed capex, PB found that Ergon Energy allocated a total of $1486 million ($2009-10) in shared costs to capex for the next regulatory control period.[1772]

PB conducted a high-level review of the cost allocation method employed by Ergon Energy to allocate shared costs. PB found an error associated with Ergon Energy's inclusion of some alternative control service costs in its opex forecast (as discussed in chapter 8). Aside from this, PB considered that Ergon Energy's application of the cost allocation method and its treatment of unregulated activities has been appropriately and transparently described and should generally lead to the correct treatment of costs. PB stated that this view is further supported by the independent review undertaken by PwC, which explicitly included a check as to whether shared costs had been correctly allocated in accordance with Ergon Energy's cost allocation method.[1773]

1768 Ergon Energy, *Regulatory proposal*, July 2009, p. 344.
1769 Ergon Energy, *Regulatory proposal*, July 2009, pp. 344–345.
1770 Ergon Energy, *Regulatory proposal*, July 2009, p. 347.
1771 PB, *Report – Ergon Energy*, October 2009, p. 17.
1772 PB, *Report – Ergon Energy*, October 2009, p. 17. Based on 77 per cent of $1.93 billion total shared costs.
1773 PB, *Report – Ergon Energy*, October 2009, pp. 18–19.

PB indicated that it assessed the prudence and efficiency of shared costs as part of its review of capex and opex at an expenditure category level. With the exception of ICT expenditure, discussed below, PB found that there were no significant increases in the gross quantity of overheads during the next regulatory control period, or variations within the line items that contribute to the pool. PB also noted that if real input cost escalation was backed out of the gross pool of shared costs, there would be a decreasing trend in expenditure evident over the next regulatory control period. For these reasons, PB concluded that Ergon Energy's shared costs, except for ICT costs, are prudent and efficient.[1774]

In order to establish the underlying prudence and efficiency of the proposed forecast ICT expenditure, PB reviewed the ICT capex proposed by both Ergon Energy and SPARQ (as it relates to Ergon Energy) and considered these as if they were one proposal.[1775]

After reviewing Ergon Energy's regulatory proposal and supporting documentation, PB requested further information from Ergon Energy and SPARQ to demonstrate the prudence and efficiency of the proposed ICT program.[1776] PB conducted a detailed review of this material in order to substantiate the proposed expenditure through demonstration of business cases and in the context of historical data.[1777]

PB noted that, of the $218 million ($2009–10) of ICT expenditure proposed by Ergon Energy and SPARQ, $166 million was 'steady state', or business as usual, expenditure and $52 million was for new capability. Over 80 per cent of new capability expenditure was for two projects, 'DMS foundation' and 'Field force automation'.[1778]

In assessing the proposed ICT expenditure, PB focused on proposed new capabilities, having regard to:[1779]

- strategic alignment of individual ICT projects or programs with Ergon Energy's broader strategies, policies or other objectives and drivers
- project need, materiality and timing
- options analysis, including explanation as to why the preferred option is the most efficient
- financial and/or economic appraisal that demonstrates value for money, cost savings and/or net benefits of the project or program
- procurement and delivery strategy.

1774 PB, *Report – Ergon Energy*, October 2009, p. 19.
1775 PB, *Report – Ergon Energy*, October 2009, p. 72.
1776 PB, *Report – Ergon Energy*, October 2009, p. 75.
1777 PB, *Report – Ergon Energy*, October 2009, pp. 76–80.
1778 PB, *Report – Ergon Energy*, October 2009, p. 76.
1779 PB, *Report – Ergon Energy*, October 2009, pp. 76–77.

In relation to ICT capex proposed by SPARQ, PB found that Ergon Energy was able to provide some supporting material for new capability projects that generally demonstrated the need for the expenditure. However, PB found that the proposed expenditures were not supported by investment analysis that demonstrated prudence and efficiency. One exception to this was $4.9 million ($2009-10) of expenditure proposed for reconfiguration of the data centre, for which PB found a more robust business case than other proposed projects.[1780] As a result, PB concluded that, with the exception of expenditure for reconfiguration of the data centre, the proposed expenditure associated with the new capability initiatives capitalised within SPARQ has not been shown to be prudent or efficient and recommends a business as usual ICT expenditure forecast.[1781]

To calculate the reduction in the service charge associated with SPARQ capex, PB used the 2008-09 SPARQ service charge as the base year cost and assumed the increase in the ICT shared cost during the next regulatory control period is predominately driven by SPARQ capex. PB then applied a reduction to the increases in the SPARQ service charge that is proportional to the reduction recommended for the SPARQ ICT capex.[1782] These steps are presented in Table G.18.

PB estimated that its recommended $20.4 million ($2009–10) reduction in ICT shared costs results in a $15.7 million reduction in capex and a $4.7 million reduction in opex over the regulatory control period.[1783]

Table G.18: Recommended reduction in ICT shared costs expenditure – SPARQ ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ICT overheads	70.9	82.6	92.7	95.7	92.7	434.6
ICT baseline costs (2008–09 year)	61.0	61.0	61.0	61.0	61.0	305.2
Increase in ICT ($m)	9.8	21.6	31.7	34.7	31.6	129.4
% reduction in SPARQ capex recommended by PB	–17.6	–28.9	–10.7	–11.7	–15.9	–17.6
Proportional reduction in ICT overhead	–1.7	–6.2	–3.4	–4.1	–5.0	–20.4
Reduction in capex shared cost	–1.3	–4.8	–2.6	–3.2	–3.8	–15.7
Reduction in opex shared cost	–0.4	–1.4	–0.8	–0.9	–1.2	–4.7
PB recommended ICT overhead	69.1	76.4	89.3	91.7	87.7	414.2

Source: PB, *Report – Ergon Energy*, October 2009, p. 20.
Note Reductions in shared costs allocated to capex and opex based on the 77:23 allocation of shared costs to capex and opex that result from Ergon Energy's cost allocation methodology.

[1780] PB, *Report – Ergon Energy*, October 2009, pp. 77–79.
[1781] PB, *Report – Ergon Energy*, October 2009, p. 80.
[1782] PB, *Report – Ergon Energy*, October 2009, pp. 19–20.
[1783] PB, *Report – Ergon Energy*, October 2009, p. xvi.

AER considerations

The AER notes that PB has assessed the prudence and efficiency of shared costs as part of its review of capex (and opex) at an expenditure category level and found that there were no significant step changes in expenditure.

The AER notes that the bulk of Ergon Energy's ICT is delivered by SPARQ and covered by a service charge to Ergon Energy. The AER considers that PB's review of SPARQ's ICT capex is an appropriate method of determining the prudence and efficiency of SPARQ's service charges to Ergon Energy.

The AER notes that the majority of ICT expenditure proposed by SPARQ is for a business as usual level of capability. The AER considers that PB's focus on expenditure for new capabilities is appropriate. This is because the efficiency and prudency of business as usual expenditure is likely to have been better established compared to expenditure for new capabilities.

The AER notes that PB has conducted a detailed review of the proposed new capabilities, having had regard to a range of considerations, including project need and efficiency, options analysis and delivery strategy. As a result, the AER accepts PB's finding that expenditure proposed for reconfiguration of the data centre is appropriate.

Regarding other projects for new capability, the AER notes PB's finding that proposed expenditure is not supported by analysis that demonstrated prudence or efficiency. On this basis, the AER considers that expenditure proposed for new ICT capability is not supported, with the exception of expenditure on reconfiguration of the data centre. As discussed in section J.3.6 of appendix J to this draft decision, the AER also rejects shared costs proposed by Ergon Energy for sponsorship and other community engagement activities.

The AER requested that Ergon Energy model the impact of the AER's decision on shared costs. Ergon Energy advised that the adjustment to shared costs allocated to capex is a reduction of $39 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal and PB's report, the AER is not satisfied that Ergon Energy's forecast of shared costs reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed allocation of shared costs to capex by $39 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

G.5.6 Deliverability of the forecast capex program

This section examines the methods proposed by Ergon Energy to deliver its proposed capex program within the next regulatory control period in the context of determining whether the AER is satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria.

Ergon Energy regulatory proposal

Ergon Energy stated that its forecast capex and opex work program for the next regulatory control period continues a well established historical trend of increasing levels of work. Specifically, Ergon Energy estimated that its workload will increase by 9.5 per cent annually over the period which, allowing for a 3 per cent annual productivity improvement, will require work force growth of around 6.5 per cent each year.[1784]

Ergon Energy stated that it has achieved this level of growth previously in a tight labour market and is therefore confident that it can be achieved again.[1785] Ergon Energy cited a number of other reasons why it is confident of delivering its proposed works program, including the following:[1786]

- it intends to extend its alternative provider model (involving the contestability of works) for urban residential development subdivisions to include commercial, industrial and large customer initiated capital works
- during 2008–09, Ergon Energy implemented a range of organisational improvements designed to manage future workload growth
- its apprentices and technical trainees are currently graduating at a rate that makes Ergon Energy largely self-sufficient in trade and technical roles and it has a good stock of graduate engineers
- it currently enjoys relatively low levels of workforce attrition and does not expect to be materially impacted by age-related attrition during the next regulatory control period
- it expects its existing workforce diversity strategies to help maintain a broad resource pool.

Consultant review

PB reviewed Ergon Energy's ability to deliver its proposed works program during the next regulatory control period.[1787]

PB noted that even though Ergon Energy's internal staffing levels are forecast to increase by 31 per cent over the next regulatory control period, a significant increase in outsourcing will be required for Ergon Energy to deliver its proposed works program. PB stated that Ergon Energy will also have to ensure delivery of materials necessary to construct the proposed capital works.[1788]

To form a view on Ergon Energy's ability to deliver its proposed work programs, PB reviewed Ergon Energy's delivery performance during the current regulatory control

[1784] Ergon Energy, *Regulatory proposal*, July 2009, p. 349.
[1785] Ergon Energy, *Regulatory proposal*, July 2009, p. 350.
[1786] Ergon Energy, *Regulatory proposal*, July 2009, pp. 350–351.
[1787] PB, *Report – Ergon Energy*, October 2009, pp. 149–154.
[1788] PB, *Report – Ergon Energy*, October 2009, p. 149.

period and the strategies Ergon Energy has put in place to increase its service delivery capability.

PB found that Ergon Energy has undertaken only a high-level and cursory review of its capability to deliver the forecast program of works and that this introduced an element of risk to delivery of the program.[1789] However, PB also considered that this risk was not likely to prevent Ergon Energy from delivering its program of works in the timeframes proposed, on the basis that Ergon Energy:[1790]

- has demonstrated it can ramp up its program of works significantly, as shown in 2006–07 and 2008–09
- has a number of strategies in place to engage and retain its internal ageing workforce, and to attract new employees
- has proposed capex that includes a significant component of urban zone substations, which are well suited to outsourcing
- has well established technical standards for undertaking the design and construction of works, as well as to maintain its assets
- has long standing relationships with third party contractors to supply both labour and materials
- undertakes a reasonable amount of non-regulated work and that these resources can be used to balance regulated work needs
- will benefit from a reasonable level of competition from external contractors for a significant portion of the increases in the program of works.

PB considered that the material procurement practices historically employed by Ergon Energy provide some confidence that it will be able to source the necessary plant, equipment and materials to deliver its program of works, but noted some doubts in relation to materials purchases with long lead times.[1791]

On the basis of the above findings, PB concluded that Ergon Energy should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.[1792]

AER considerations

The AER is concerned by PB’s finding that Ergon Energy has undertaken only a high-level and cursory review of its capability to deliver the forecast program of works, particularly given that it represents a significant increase compared to the level of investment undertaken in the current regulatory control period.

1789 PB, *Report – Ergon Energy*, October 2009, p. 153.
1790 PB, *Report – Ergon Energy*, October 2009, p. 154.
1791 PB, *Report – Ergon Energy*, October 2009, p. 153.
1792 PB, *Report – Ergon Energy*, October 2009, p. 154.

However, the AER considers that there are numerous reasons that more than off-set this concern, which together suggest that Ergon Energy is likely to be able to deliver its proposed capex program.

The AER considers a key reason is that Ergon Energy has demonstrated its ability to significantly expand its work program during the current regulatory control period. For example, PB found that Ergon Energy delivered increases in key capex asset classes between 2005–06 and 2006–07 at a rate similar to that required in the next regulatory control period.[1793] PB also highlighted that in 2008–09, Ergon Energy delivered capex of $818m, which was significantly higher than the forecast capex of $732m.[1794] The fact that Ergon Energy achieved these increases in the relatively tight labour market that accompanied the recent resources boom supports its claims in relation to future capex delivery.

The AER also notes PB's findings in relation to the aspects of Ergon Energy's proposed capex that make it suited to outsourcing, and Ergon Energy's well established materials procurement practices.

For the reasons discussed above, the AER considers Ergon Energy should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.[1795]

Having considered Ergon Energy's forecast capex program and proposed delivery strategies, and the advice of PB, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is satisfied that the deliverability of Ergon Energy's forecast capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

The AER notes that the deductions it has proposed for Ergon Energy's forecast capex elsewhere in this draft decision provides further confidence that Ergon Energy will be able to deliver its program of works.

G.6 AER conclusion

The AER has reviewed Ergon Energy's proposed forecast capex allowance and, for the reasons set out in this appendix, the AER is not satisfied that the proposed forecast capex allowance reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER. In particular the AER considers:

- the proposed growth capex does not reflect a realistic expectation of the demand forecast required to achieve the capex objectives

[1793] PB, *Report – Ergon Energy,* October 2009, p. 153.
[1794] PB, *Report – Ergon Energy,* October 2009, p. 153.
[1795] PB, *Report – Ergon Energy,* October 2009, p. 154.

- Ergon Energy's proposed asset replacement capex does not reflect the efficient costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the capex objectives

- the proposed reliability and quality improvement capex, in particular the feeder improvement program, has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the capex criteria

- the expenditure associated with major building projects and the ICT systems change program has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the capex criteria.

As the AER is not satisfied that the total capex allowance reasonably reflects the capex criteria, under clause 6.5.7(d) of the NER the AER must not accept the forecast capex proposed by Ergon Energy. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the capex for Ergon Energy over the next regulatory control period which it is satisfied reasonably reflects the capex criteria, taking into account the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capex for Ergon Energy is $5013 million, as set out in table G.19.

Table G.19: AER draft decision on Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
Adjustment to growth capex	–155.1	–179.5	–140.9	–168.2	–200.5	–844.2
Adjustment to asset replacement capex	–9.9	–19.4	–30.9	–30.0	–28.6	–118.8
Adjustment to reliability and quality improvement capex	–2.6	–4.5	–7.1	–9.8	–11.4	–35.3
Adjustment to non–system capex	–95.6	–115.7	–50.6	1.7	6.6	–253.5
Adjustment to shared costs	–2.2	–5.9	–9.2	–9.8	–11.5	–38.6
Re-inclusion of shared costs removed in the adjustments to growth, asset replacement, reliability and non–system capex	40.6	48.3	36.0	30.6	32.6	188.1
Adjustment to cost escalators	–16.2	2.0	22.2	37.6	36.5	82.1
AER capex allowance	845.4	925.2	996.8	1080.0	1165.3	5012.8

Note: Totals may not add due to rounding.
The shared costs included in deductions to growth, asset replacement, reliability and non–system capex are not to be removed from Ergon Energy's capex allowance. This is because the AER has not proposed any adjustments to Ergon Energy's shared costs, with the exception of adjustments for ICT services, sponsorship and community engagement activities, as discussed in section G.5.5.

H. Real Cost Escalators

H.1 Introduction

In recent regulatory determinations for electricity NSPs, the AER has allowed capex and/or opex allowances to be escalated, in real terms, for expected input cost increases.[1796] This involves the disaggregation of expenditure allowances into specific inputs (for example labour, land and materials) which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to changes in the real price level. The nominal price level (that is the real price plus inflation) is taken into account when prices and revenues are adjusted at the aggregated level under the CPI–X control mechanism.

The methodology employed to determine the real cost escalators generally combines forecast movements in the price of input components with weightings for the relative contribution of each of the components to final equipment/project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business, given differences in composition of their respective expenditure forecasts.

PB has reviewed the weightings applied by the Qld DNSPs, as well as the application of the resultant escalators in the Qld DNSPs' capex and opex models. The AER's considerations of specific modelling applications of the real cost escalation factors assessed in this appendix, are set out in chapters 7 (capex) and 8 (opex).

Historically, the objective of introducing real cost escalation has been to take account of the impact of the commodities boom and skills shortages in the engineering field in Australia in recent years. In light of these external factors, the AER has considered that cost escalation at CPI did not reasonably reflect a realistic expectation of the movement in some of the input costs faced by electricity network service providers. The AER has previously expressed that the real cost escalation regime should be applied symmetrically to also reflect real cost decreases.[1797] This approach provides the opportunity for network service providers to recover the efficient costs of real increases, while ensuring that end users receive the benefit of real cost reductions.

Given that there is no futures market for the procurement and installation of electrical equipment (for example transformers, switchgear), in previous AER decisions cost

[1796] AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 478–507; AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 60–70; AER, *Draft Decision, SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007, pp. 87–91, 316–331; and AER, *Final Decision, ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, pp. 29–48.

[1797] AER, *Final Decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, p. 80.

escalation rates have been estimated with reference to the expected growth in key input ‘cost factors’ such as:[1798]

- copper
- aluminium
- steel
- crude oil
- construction costs
- electricity, gas and water (EGW) sector labour costs
- general labour costs
- land and easement costs.

All other inputs are typically escalated in line with CPI only.

In assessing the escalators proposed by the Qld DNSPs, the AER considers that its conclusions from the recent NSW, ACT and Tasmanian decisions are still generally applicable with respect to the methodology used for estimating each escalator.[1799]

The AER has a preference for updating real cost escalation factors with the most up to date forecasts at the time of its final decision. This preference is a result of the NER requirement that the capex and opex forecasts should reflect a realistic expectation of cost inputs required to achieve the capex and opex objectives.[1800] The AER considers that using the most recently available data to update cost escalation forecasts, where appropriate, satisfies this requirement.

H.2 Qld DNSP regulatory proposals

The Qld DNSPs engaged consultants to develop real cost escalation rates for the next regulatory control period. Energex engaged KPMG Australia (KPMG) and Ergon Energy engaged Sinclair Knight Merz (SKM).

SKM proposed methods for escalating base metals, oil, labour, construction costs and other inputs that are largely consistent with the methods the AER has previously applied in recent decisions.[1801]

[1798] AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 478–507; AER, *Decision, Powerlink Queensland*, 14 June 2007, pp. 60–70; AER, *Draft Decision, SP AusNet*, 31 August 2007, pp. 87–91, 316–331; and AER, *Final Decision, ElectraNet*, 11 April 2008, pp. 29–48.

[1799] AER, *Final decision, NSW DNSPs*, April 2009; AER, *Final decision, ACT DNSP*, April 2009; AER, *Final decision, TransGrid*, 28 April 2009; and AER, *Final Decision, Transend*, April 2009.

[1800] NER, clauses 6.5.6 (c) and 6.5.7(c).

[1801] For example, see AER, *Final decision, NSW DNSPs*, April 2009, pp. 478–507; and AER, *Final Decision, ElectraNet*, 11 April 2008, pp. 29–48.

KPMG proposed a method for escalating materials costs that is based on a composite index of commodity price forecasts, modelled using a range of statistical techniques together with anecdotal evidence. However, due to current volatility in commodities markets, KPMG recommended an average annual real escalation rate of zero per cent (or a nominal rate of CPI) be applied to Energex's forecast materials costs, and that a revised forecast be calculated closer to the start of the next regulatory control period. KPMG also developed specific escalation rates for land and construction costs.

KPMG also developed contractor and labour cost forecasts based on a composite index of wage data from the mining, utilities and construction sectors.

The approaches for each of the key escalators are discussed below.

H.3 Materials cost escalators

H.3.1 Energex

Energex engaged KPMG to develop escalation rates for the cost of materials over the next regulatory control period.[1802] KPMG completed its report in March 2008 and provided another report to Energex in May 2009 which updated escalation rates for materials.

Based on the available data provided by Energex and a literature survey, KPMG determined that the most appropriate methodologies to forecast materials cost escalation rates were:[1803]

- moving average estimation
- classical regression analysis[1804]
- structural time series (STS) analysis
- anecdotal evidence.

KPMG noted that previous regulatory proposals and decisions tended to fall within the range of these methodologies and that this aligned with its STS forecasts.[1805] In relation to labour escalators, KPMG considered that its STS methodology was superior to the other methodologies, for example because it more rigorously accounts for the variability in the historical data, and therefore provides more robust forecasts.[1806]

[1802] Energex, *Regulatory proposal*, July 2009, p. 176.
[1803] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG, p. 1.
[1804] KPMG's May 2009 report did not use classical regression techniques.
[1805] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG, p. 35.
[1806] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG, pp. 2, 35 and 37. For detail on KPMG's structural time series modelling, refer to appendix B.

In its March 2008 report, KPMG relied on commodities price data from the following sources:

- Australian Bureau of Agricultural and Resource Economics – aluminium, copper, iron ore and zinc
- Economist Intelligence Unit – aluminium, copper and zinc
- Deutsche – aluminium, copper and zinc
- Bloomberg – aluminium and copper.

KPMG combined data for each of the four commodity markets listed above[1807] to derive a 'reasonable point estimate' of the average annual increase in the nominal value of Energex's composite material costs over the period 2007 to 2015 of 4.5 per cent.[1808] KPMG did not provide separate escalation rates for each of the materials on which it based its composite materials escalator.

In its May 2009 report, KPMG used only moving average, STS modelling and anecdotal evidence to calculate materials cost escalation rates, and used data from only Australian Bureau of Agricultural and Resource Economics and Bloomberg. KPMG calculated a 'reasonable point estimate' of the annual increase in the real value of Energex's materials costs over the period 2010 to 2015 of 11.1 per cent.[1809] However, based on qualitative evidence from Deutsche and the Economist Intelligence Unit, which indicated significant volatility in commodity prices in 2008 and 2009, KPMG recommended a real escalation rate for materials of zero per cent with a further review to be undertaken closer to the start of the next regulatory control period.[1810]

Energex applied this recommendation for the next regulatory control period and stated that it would monitor input data over 2009 and consider the need for revising its materials escalation rate in response to the draft determination.[1811] For 2009–10, Energex retained the earlier KPMG nominal forecast of 4.5 per cent (2.05 per cent real). For 2008–09, Energex applied a real escalation rate of 1.53 per cent, reflecting the historical rate of system and non-system real cost escalation.[1812]

The real escalation rates Energex has applied to materials costs are shown in table H.1.

[1807] KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009.

[1808] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG, p. 1.

[1809] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, p. 3.

[1810] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, p. 29.

[1811] Energex, *Regulatory proposal,* July 2009, p. 178.

[1812] Energex, Response to AER request, AER.EGX.26, 5 October 2009, confidential.

Table H.1: Energex real materials cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	1.53	2.05	0	0	0	0	0

Sources: 2008–09: Energex, response to AER request, AER.EGX.26, 5 October 2009.
2009–10 to 2014–15:Energex, *Regulatory proposal*, July 2009, RIN supporting documentation, RSD 2.3.10(1), Expenditure escalation processes, p. 3, nominals converted to reals by subtracting forecast inflation rate of 2.45 per cent.

AER considerations

The real rate of materials cost escalation that Energex applied in its regulatory proposal, and which the AER must assess, does not reflect the methodology outlined by KPMG. Nevertheless, as Energex's stated intention to potentially update its materials escalation rate[1813] may involve relying on KPMG's proposed approach, the AER offers the following assessment of the approach.[1814]

The AER does not consider that the approach proposed by KPMG provides a realistic forecast of Energex's expected materials costs, for the following reasons:

- aluminium, copper, iron ore and zinc have been equally weighted rather than weighted according to Energex's actual costs.[1815] KPMG itself identified this issue, noting that more robust results could be produced using historical Energex data.[1816] The AER notes that oil, although not included in KPMG's composite materials escalator, is typically identified as a significant contributor to a DNSP's costs whereas zinc is not[1817]

- the application of a constant annual rate of materials cost escalation does not accurately represent the volatility and uncertainty of the current market, as indicated by the escalation rates calculated by the AER, shown in table H.2

- the statistical techniques used by KPMG rely on historical data and do not reflect materials prices from futures markets. Research by the International Monetary Fund suggests that models incorporating futures prices generally yield superior forecasts over horizons of one year or longer relative to models that are based on historical data only[1818]

[1813] Energex, *Regulatory proposal*, July 2009, p. 178.

[1814] As outlined in Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG; Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update; and KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009.

[1815] KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009, p. 24.

[1816] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG, p. 3.

[1817] For example, see AER, *Final Decision, NSW DNSPs*, 28 April 2009, p. 485.

[1818] IMF, Forecasting commodity prices: Futures verses judgement, March 2004, p. 4, http://www.imf.org/external/pubs/ft/wp/2004/wp0441.pdf.

- the basis of the 'reasonable point estimates' changed between the March 2008 report and the May 2009 report and was influenced by subjective judgements in the form of 'anecdotal evidence'. These factors make the method uncertain over time and difficult to replicate consistently, which is an issue in view of the AER's established preference for updating escalators using latest available data at the time of final decisions[1819]

- the additional step taken in the May 2009 report to derive a 'reasonable point estimate with subsequent review' of zero per cent disregards the data–based method. It is unclear in what circumstances the data-based method should be disregarded because of its unreliability and what alternative method should be used in its place.

The AER must assess Energex's regulatory proposal as it stands, not on the basis of what it may include after revision. As a result, the relevant question to be addressed is whether the rates of materials cost escalation applied by Energex, as indicated in table H.1, will result in a realistic expectation of Energex's costs over the next regulatory control period.

In order to make this assessment, the AER has calculated real escalation rates for key DNSP material costs identified in previous AER decisions.[1820] These are presented in table H.2 and the methods used by the AER to calculate them are outlined at the end of this appendix.

As shown in table H.2, the AER escalators indicate that most of the negative material cost impacts associated with the global financial crisis (GFC) occur in 2008–09 and 2009–10, with costs expected to rebound strongly early in the next regulatory control period.

Table H.2: AER real cost escalators for aluminium, copper, steel and oil (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–18.8	–12.0	20.2	16.1	5.5	1.6	0.4
Copper	–27.3	10.4	14.7	10.6	1.1	–2.6	–3.9
Steel	7.1	–29.4	28.6	21.0	4.6	0.6	–0.8
Oil	–17.3	–8.3	22.0	15.8	5.5	1.7	0.4

Source: AER analysis.

A more meaningful assessment of Energex's proposed materials escalator can be made by calculating a composite of the escalators in table H.2, weighted by the contribution of each of these to Energex's actual materials costs. However, as noted by PB, Energex's application of a zero per cent escalation rate for all materials means that cost weightings were not used.[1821] KPMG adopted equal 25 per cent weightings

[1819] For example, see AER, *Final Decision, NSW DNSPs*, 28 April 2009.
[1820] For example, see AER, *Final Decision, NSW DNSPs*, 28 April 2009.
[1821] PB, *Report* – Energex, October 2009, p. 10.

for aluminium, copper, steel and zinc[1822] in the absence of actual Energex weightings data, which KPMG stated would result in more robust escalators.[1823]

Table H.3 shows weightings data the AER has for other DNSPs. The AER notes that escalation rates for aluminium, copper, steel and oil were applied to around only 25 per cent of the total materials costs of these DNSPs. The AER also notes that this percentage appears to be smaller for DNSPs, such as Energex, that have higher customer densities, as indicated by customer numbers per kilometre of line length. As noted in section H.1, other materials costs were escalated at CPI, or at zero per cent in real terms.

Given that Energex has a broadly similar customer density to Energy Australia and Integral Energy, the AER has averaged the cost weightings data for EnergyAustralia and Integral Energy to weight the materials cost escalators presented in table H.3. The resultant materials escalation rates are presented in table H.4.

Table H.3: Customer densities and shares of aluminium, copper, steel and crude oil in total materials costs of selected DNSPs

DNSP	Customer/km line length 2007–08	Share of aluminium, copper, steel and oil in total materials costs (%)
EnergyAustralia	31.9	16.5
Integral Energy	25.6	7.5
Energex	23.7	NA
ETSA EGW	9.2	33.9
Country Energy	3.8	41.0

Source: AER analysis.

Table H.4: AER and Energex materials cost escalation rates (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
AER indicative escalation rates	–2.38	0.02	2.18	1.59	0.29	–0.16	–0.32
Energex proposed escalation rates	1.53	2.05	0	0	0	0	0

Sources: Energex, response to AER request AER.EGX.26, 5 October 2009, and AER analysis.

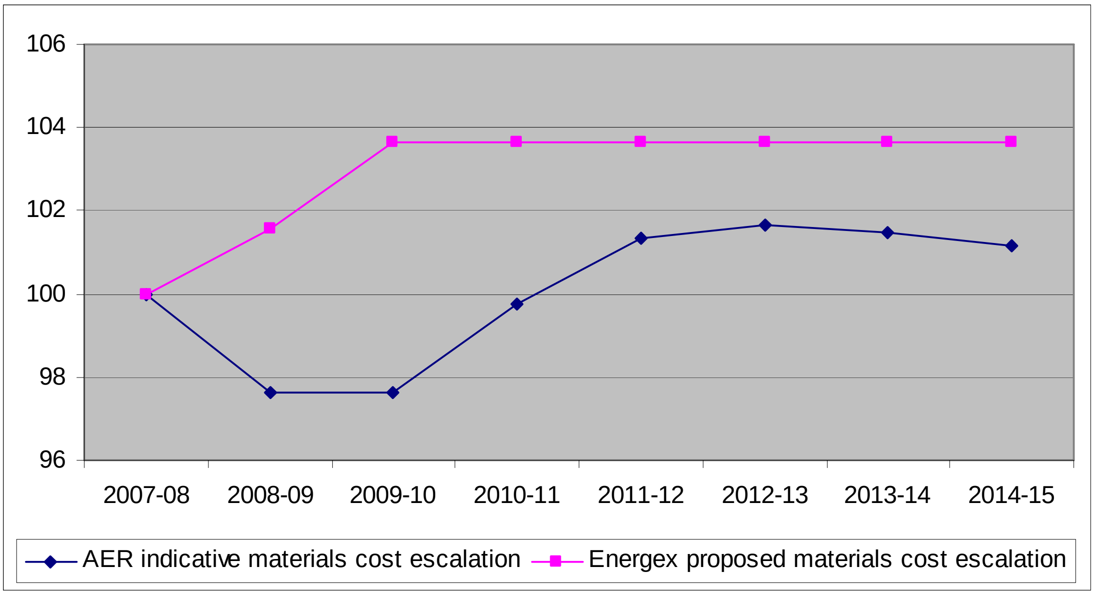
The impact of these cost escalators on costs during the next regulatory control period is shown in figure H.1. It is clear that, because Energex has increased its materials costs in 2008–09 and 2009–10, when costs actually fell significantly and then remained steady, Energex's forecasts of materials costs during the next regulatory

1822 KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009, p. 24.

1823 Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG, p. 3.

control period appear to be significantly higher than levels suggested by the AER escalation rates. This is despite the strong recovery in materials prices expected in the early part of the next regulatory control period indicated by the AER's forecast materials escalation rates in table H.2.

Figure H.1: Comparison of Energex proposed materials cost escalation and AER indicative materials cost escalation (index base year 2007–08 = 100)



Source: AER analysis.

The AER acknowledges that using a small sample of other DNSPs' cost weightings is not ideal, but considers that using some actual weightings data provides a more realistic expectation of Energex's future costs than using none.

The AER also notes that had it used only the cost weightings for Integral Energy, on the basis that its customer density is closest to Energex's, the AER escalator line in figure A.1 would be shifted downwards for the period 2010–11 to 2014–15. However, the AER has decided to include EnergyAustralia's weightings in its analysis in order to provide a more representative (albeit still very limited) sample of DNSPs' cost weightings. On this basis, the AER considers that the escalation rates it has calculated represent the minimum adjustment to Energex's proposed escalators needed to provide a realistic expectation of Energex's materials costs in the next regulatory control period.

AER conclusions

The AER's conclusions on forecast growth in real materials costs for Energex are set out in table H.5.

Table H.5: AER conclusion on Energex real materials cost escalation rates (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials cost escalation rates	–2.38	0.02	2.18	1.59	0.29	–0.16	–0.32

For the reasons discussed and as a result of the AER's analysis of Energex's regulatory proposal, the AER is not satisfied that Energex's proposed materials cost escalation forecasts reasonably reflect the capex and opex criteria, including the capex and opex objectives. The AER considers that the materials escalation rates shown in table H.5 represent the minimum adjustment necessary for materials cost forecasts to comply with the NER. In coming to this view, the AER has had regard to the capex and opex factors.

H.3.1.1 Land and easements

Energex engaged KPMG to update materials cost escalators prepared in March 2008 and, where necessary, develop cost escalators for other materials.[1824] As part of this process, KPMG developed real cost escalators for Energex's land and easements.[1825]

KPMG's real land cost escalator of 2.0 per cent represents its 'reasonable point estimate' informed by weighting the results of simple moving average (SMA) computations, STS modelling and anecdotal evidence. KPMG's STS modelling is based on:

- ABS annual historical land value data for commercial, residential and rural land in Queensland
- historical Queensland gross state product (GSP) data
- KPMG Econtech's Queensland GSP forecasts.[1826]

SMA estimates were based solely on historical ABS land value data.[1827]

KMPG estimated forecast land and easement growth rates ranging between 1.4 to 8.3 per cent for the next regulatory control period. KPMG noted its reasonable point estimate, of 2 per cent, was determined by averaging its STS and SMA forecasts, weighted at 80 per cent and 20 per cent, respectively. KPMG considered this was appropriate given the STS modelling had capacity to account for structural shifts in the economy and SMA estimation was effective for variables that moved in a

[1824] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG.

[1825] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, pp. 1, 6.

[1826] KPMG Econtech's analysis found that Queensland GSP and land values were closely correlated.

[1827] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, p. 33.

relatively stable manner over the long term, such as land values.[1828] KPMG's real land and easement forecast is shown in table H.6

Table H.6: KPMG real land and easement growth rates (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Land and easements	2.0	2.0	2.0	2.0	2.0	2.0

Source: KPMG, *Energex: Development of Cost Escalation Rates*, May 2009, p. 23.

AER considerations

The AER has tested the reasonableness of KPMG's land and easement escalator, with reference to the full historical series (1989–2008) of Queensland land value data published by the ABS.[1829] The AER derived an average nominal growth rate based on ABS land type categories (residential, commercial and rural) which was then deflated by the Brisbane CPI to calculate a real historical annual growth rate.[1830] This analysis indicated that KPMG's land and easement escalator was conservative compared to the long term historical average. This outcome is, however, not unexpected given that KMPG's modelling draws on macroeconomic forecasts of GSP, which are more likely to capture the impact of recent economic developments.

The AER acknowledges that the general statistical techniques used by KPMG are widely recognised estimating methods. While KPMG's use of GSP forecasts and STS modelling represents a more rigorous approach to land forecasting than the AER's historical averaging, the AER is not privy to KPMG's model diagnostics and cannot verify the statistical significance of the explanatory variables or the robustness of the modelling at a detailed level.

However, in the absence of recognised and widely available alternative land value forecasts, the AER considers it appropriate in this case to assess the reasonableness of KPMG's actual estimate, separate from the methodology used to derive it.

Based on its own analysis of historical growth rates, the AER considers that Energex's proposed real land escalator of 2 per cent appears reasonable for the next regulatory control period. However, while it accepts the forecast escalator as reasonable, the AER does not necessarily accept that the methodology used to derive it will continue to provide reasonable estimates in the future.

AER conclusions

For the reasons discussed, and as a result of the AER's analysis of Energex's regulatory proposal and supporting information, the AER is satisfied that Energex's land and easement growth estimate reasonably reflects the capex criteria, including

[1828] KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009, p. 14.

[1829] ABS, Cat No: 5204.0 *Australian System of National Accounts*, table 61, Value of Land, by Land use by State/Territory, as at 30 June, current prices.

[1830] ABS, Cat No: 6401.0, *CPI: Group, Sub-group and Expenditure Class, Percentage change from corresponding quarter of previous year by Capital City*, table 14.

the capex objectives. In coming to this view, the AER has had regard to the capex factors.

The AER's conclusion on forecast land and easement growth rates for Energex are set out in table H.7.

Table H.7: AER conclusion on Energex's real land and easements growth rates (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Land and easements	2.0	2.0	2.0	2.0	2.0	2.0	2.0

H.3.1.2 Construction and building costs

Energex engaged KPMG to update the materials cost escalators that it prepared in March 2008[1831] and, where necessary, develop cost escalators for other material cost categories. KPMG recommended in its January 2009 interim report to Energex that it should develop construction cost escalators. Energex endorsed KPMG's recommendation.[1832]

KPMG used the SMA and STS modelling methods to develop its construction and buildings cost forecasts.[1833]

KPMG noted the absence of robust data due to the recent economic downturn which resulted in reduced accuracy for forecasts from both the SMA estimation and STS modelling. Consistent with the approach it took in its March 2008 report, KPMG considered forecasts provided by the STS modelling to be more robust than SMA estimation, as it more effectively accounted for variability in historical data and recent shifts in domestic and global economic conditions. KPMG gave greater consideration to both qualitative analysis and previous regulatory decisions, compared with its March 2008 report, in developing its construction and buildings cost forecasts.[1834]

KPMG used ABS data when developing its construction cost escalators.[1835] Specifically, KPMG used data for the value of work done in Queensland for the period June quarter 1998 to June quarter 2008. KPMG considered this approach to be consistent with that accepted by the AER, given this data source used was the same as

[1831] Energex, *Regulatory proposal*, July 2009, appendix 12.6, Final report on escalation rates for labour, materials and contractors by KPMG.
[1832] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, pp. 1–2, 6.
[1833] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, p. 28.
[1834] Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, pp. 2, 29 and; KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009, p. 4.
[1835] ABS, Cat No: 8762.0, *Engineering Construction Activity*, Table 02 – Value of work done Queensland, Chain Volume Measure, September 2008.

that applied by Econtech to develop its construction cost forecasts for the Construction Forecasting Council (CFC).[1836]

KPMG estimated construction cost forecasts to range between 10.2 to 10.5 per cent for the next regulatory control period. Given the recent slowdown in the growth of construction work done, KPMG decided to rely largely on its STS modelling forecasts which more effectively account for this slowdown.[1837] KPMG's construction and buildings cost forecasts are shown in table H.8.

Table H.8: Energex's real construction building cost growth rates for Queensland (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Construction costs	10.2	10.2	10.2	10.2	10.2	10.2

Source: Energex, *Regulatory proposal*, July 2009, p. 213; and KPMG, Energex: Development of cost escalation rates – Final Report, May 2009, p. 26.

AER considerations

The AER notes KPMG placed greater reliance on STS modelling to determine construction cost forecasts, as it considered this method accounted for the variability in historical data.[1838] The AER further notes KPMG applied the ABS engineering construction activity data to derive its construction cost forecasts.[1839]

The AER has reviewed the information supporting KPMG's methodology to derive its construction cost forecasts. The AER does not consider that the proposed methodology adequately considers historical data. Based on the information provided, the AER considers the application of CFC's methodology to be more robust in considering historical data. The AER notes that CFC considers the following two historical data sources to be of particular importance in determining its construction cost forecasts:[1840]

- Engineering Construction Activity, ABS, Cat No. 8762.0
- Building Activity, ABS Cat No. 8752.0.

The AER notes that KPMG has only applied the former and the AER does not consider Engineering Construction Activity rates on its own provide sound basis for deriving building cost escalators.

1836 Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, p. 15.

1837 Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, p. 28 and; KPMG, Response to AER information requests on KPMG cost escalation reports, September 2009, pp. 15–17.

1838 Energex, *Regulatory proposal*, July 2009, appendix 12.7, Final report on escalation rates for labour, materials and contractors by KPMG, May 2009 update, pp. 2, 29.

1839 ABS Cat No. 8762.0, *Engineering Construction Activity*, Table 02 – Value of work done Queensland, Chain Volume Measure, September 2008.

1840 http://www.cfc.acif.com.au/analysis2.asp, accessed 17 September 2009.

The AER further notes a material difference which exists between the construction cost forecasts determined by KPMG and the CFC. The AER considers that KPMG's forecast, which assumes a constant escalation rate for each year of the next regulatory control period, is unlikely to reflect the volatility and uncertainty of the current economic climate or currently available macroeconomic projections. The AER therefore, does not consider KPMG's construction cost growth forecast is demonstrated to be reasonable. The AER considers CFC's forecasts are more likely to represent a reasonable expectation of future construction costs likely to be incurred by Energex, given CFC's forecasting methodology considers more historical data and recent macroeconomic forecasts.

The AER considers it reasonable to apply the updated CFC engineering construction cost forecasts as they reflect the most recent data available.[1841] The AER deflated the CFC forecasts with KPMG Econtech's Australia National State and Industry Outlook (ANSIO) CPI forecasts to determine real forecasts.[1842] The AER considers the updated forecasts reflect a reasonable expectation of movements in construction costs over the next regulatory control period and will therefore apply updated CFC construction cost forecasts as a proxy for buildings materials cost escalators proposed by Energex.

AER conclusions

For the reasons discussed and as a result of the AER's analysis of Energex's regulatory proposal and supporting information, the AER is not satisfied that Energex's construction cost forecasts reasonably reflect the capex and opex criteria, including the capex and opex objectives. The AER considers that Energex's construction cost escalators should be adjusted to reflect the latest forecasts developed by the CFC, and is the minimum adjustment necessary for its construction cost escalators to comply with the NER. In coming to this view, the AER has had regard to the capex and opex factors. The AER's conclusions on Energex's forecast construction cost escalators are set out in table H.9.

Table H.9 AER conclusion on Energex's real construction costs escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Construction costs	2.8	1.1	–0.9	–0.2	1.0	0.0	–1.5

H.3.2 Ergon Energy

Ergon Energy applied the following escalators, as derived by SKM, in its regulatory proposal:[1843]

- aluminium and copper

[1841] The AER accessed the CFC's published May 2009 forecasts on 14 September 2009.
[1842] Econtech, *Australian National State and Industry Outlook*, 20 August 2009, p. 110.
[1843] Ergon Energy, *Regulatory proposal*, July 2009, pp. 337–339.

- steel
- crude oil
- construction costs
- building costs
- exchange rates and inflation (used to develop the materials cost escalators)
- Trade Weighted Index (TWI).

H.3.2.1 Aluminium and copper

As discussed in chapter 7, aluminium and copper were two of the key materials that SKM identified as influencing Ergon Energy's costs.[1844]

The method proposed by SKM to develop cost escalators for aluminium and copper costs is to firstly determine the average of the last 30 days of London Metals Exchange (LME) spot prices for aluminium and copper, and the LME 3 month, 15 month and 27 month contract prices for aluminium and copper. The Consensus Economics long term forecasts (taken as 7.5 years from the survey date) for aluminium and copper prices were also determined. Each of the above data points was then interpolated to produce a monthly average prices series for aluminium and copper respectively.[1845]

SKM uses financial year average (July to June) to convert monthly nominal aluminium and copper prices to yearly averages. SKM adjusted the nominal United States dollar (USD) aluminium and copper prices to nominal Australian dollar (AUD) values using SKM forecast USD/AUD exchange rates.

Based on this approach, the escalation rates for aluminium and copper that SKM calculated for Ergon Energy are shown in table H.10.

Table H.10: SKM real aluminium and copper cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–45.6	–1.8	12.7	12.4	11.8	13.1	11.2
Copper	–57.1	–10.0	6.7	7.7	8.2	10.0	8.6

Sources: Real percentage changes calculated on the basis of SKM's proposed CPI forecasts and commodity forecasts, p. 1 and p. 4 respectively of Ergon Energy, Regulatory Proposal, document PL651c, Electricity Industry Labour, Commodity and Asset Price Cost Indices, January 2009, which replaces the incorrect attachment AR461 by the same title.

1844 Ergon Energy, *Regulatory proposal*, July 2009, p. 337.
1845 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, pp. 25–26.

AER considerations

The method proposed by SKM to forecast the escalation of aluminium and copper costs for Ergon Energy is the same as that allowed by the AER in recent decisions for TNSPs and DNSPs.[1846] To summarise previous decisions, the method adopted by SKM was considered reasonable by the AER for the following reasons:

- the AER considered that using two data sources (LME and Consensus Economics) was reasonable because it captures market data up to the extent it is available and includes credible views from a range of professional forecasters on the price of aluminium and copper.[1847]
- the AER considered that a linear interpolation between the LME forecasts and the Consensus Economics' long term forecasts appears to be the most reasonable approach to merge the short-term LME data with Consensus Economics' long term forecasts.[1848]
- the AER considered that using a monthly average of LME forward contract prices is more appropriate than using prices from a single day because it removes potential price distortions that may arise on a single day.[1849]

The AER notes that since the earlier decisions in which these views were expressed, prices for aluminium and copper futures contracts have become available for a period that covers the next regulatory control period. As a result, it is no longer necessary to rely on economic forecasts as an indicator of future aluminium and copper prices. The AER notes that SKM's preferred approach is to use commodity futures contract prices in preference to economic forecasts, on the basis that: [1850]

- forward contract markets for aluminium and copper are well established and sufficiently liquid to indicate future prices
- futures contracts represent the stated future position of market participants who have actively placed money behind their individual predictions
- futures contract markets provide greater and more immediate financial risk than economic forecasts that do not involve any direct financial risk to the forecasters.

The AER considers that cost escalators based on futures contract prices alone provide a more accurate indication of future materials costs that escalators based on a combination of futures contract prices and economic forecasts.

The AER notes that SKM adjusted the nominal USD aluminium and copper prices to real AUD values using SKM forecast exchange rates and SKM forecast Australian

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[1846] For example, see AER, *Final decision, NSW DNSPs*, pp. 478–507; and AER, *Final Decision, ElectraNet*, 11 April 2008, pp. 29–48.

[1847] AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.

[1848] AER, *Draft decision, NSW DNSPs*, November 2008, p. 545.

[1849] AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.

[1850] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, p. 23.

CPI. As discussed below, the AER does not agree with the approaches SKM has taken on exchange rates (sections 3.2.5) and inflation (section 3.2.7).

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, the AER considers that the method adopted by SKM does not provide a realistic expectation of the cost of aluminium and copper required for Ergon Energy to achieve the capex objectives in the next regulatory control period.

In addition to the issues identified above, the AER considers that to develop a robust forecast it is appropriate to update the forecast materials cost escalators using the most recent data.[1851]

The AER considers that these are the minimum adjustments necessary to ensure that the material cost escalators used by Ergon Energy provide a realistic expectation of the cost of aluminium and copper.

AER conclusions

Based on the most recent data at the time of this draft decision and the methodology outlined at the end of this appendix, the AER's conclusions on real aluminium and copper escalators for this draft decision are presented in table H.11.

Table H.11: AER estimates of Ergon Energy's real aluminium and copper cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–18.8	–12.0	20.2	16.1	5.5	1.6	0.4
Copper	–27.3	10.4	14.7	10.6	1.1	–2.6	–3.9

Source: AER analysis.

H.3.2.2 Steel

Ergon Energy engaged SKM to forecast real growth in Ergon Energy's materials costs, which included taking account of changes in the cost of steel.[1852]

SKM stated that it was not possible to forecast steel costs using the same methodology used for aluminium and copper because there is no liquid futures market for steel. SKM considered that the Commodities Research Unit (CRU) steel price index and Consensus Economics forecasts (Hot Rolled Coil variety) provided the best available outlook for steel over the short and long term. The Consensus Economics publication provides two separate forecasts for steel prices, one being relative to the US domestic market and the other for the European domestic market. SKM used the average of the US and European quarterly forecast market prices for steel as the best representative of the price for steel.[1853]

[1851] AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.
[1852] Ergon Energy, *Regulatory proposal*, July 2009, p. 337.
[1853] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008 pp. 28–29.

The method proposed by SKM to escalate steel costs was to use the CRU steel price index for escalating historical steel costs and then linear interpolate this series with forecasts of quarterly market prices from Consensus Economics. This series is then further interpolated with the Consensus Economics long term forecast (taken as 7.5 years from the survey publication date) to establish forecast steel prices for the remainder of the regulatory control period.[1854] The forecasts are then converted from nominal USD to nominal AUD using SKM's USD/AUD exchange rate forecast.

Based on this approach, the escalation rates for steel that SKM calculated for Ergon Energy are shown in table H.12.

Table H.12: SKM's real steel cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Steel	–33.8	3.7	11.5	6.4	3.1	5.5	4.6

Sources: Real percentage changes calculated on the basis of SKM's proposed CPI forecasts and commodity forecasts, p. 1 and p. 4 respectively of Ergon Energy, *Regulatory proposal*, document PL651c, Electricity Industry Labour, Commodity and Asset Price Cost Indices, January 2009, which replaces the incorrect attachment AR461 by the same title.

AER considerations

The method proposed by SKM to forecast the escalation of steel costs for Ergon Energy is similar to that allowed by the AER in recent decisions for TNSPs and DNSPs.[1855] This method is outlined at the end of this appendix. However, the AER has identified two issues in relation to SKM's methodology.

The AER notes that to calculate historical steel costs, SKM used CRU steel price data, which the AER understands to be a weighted average of steel industry prices that includes, but is not limited to, hot rolled coil variety steel. The AER therefore considers that the resultant measure of historical steel costs would not be consistent with the Consensus Economic forecast for hot rolled coil variety steel than, for example, the Bloomberg hot rolled coil variety steel price data currently used by the AER.

The AER notes that SKM's conversion of the long term (5–10 years) Consensus Economics forecasts in real US dollars directly into real Australian dollars using the USD/AUD nominal exchange rate assumes that inflation differences between the two countries are already accounted for. While SKM did not provide any evidence that this assumption holds, the AER notes that the issue can be avoided entirely if the following approach is adopted:

[1854] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008 p. 29.

[1855] For example, see AER, *Final decision, NSW DNSPs*, pp. 478–507; and AER, *Final Decision, ElectraNet*, 11 April 2008, pp. 29–48.

- convert real USD prices into nominal USD terms using US Congressional Budget Office historical and forecast US inflation data (this information is publicly available and is from a credible source)[1856]

- convert the nominal USD prices into nominal AUD prices using historical and forecast USD/AUD exchange rate

- use Reserve Bank of Australia (RBA) historical and forecast inflation data to convert prices into real AUD terms.

This approach is consistent with the AER's previous decision for the NSW DNSPs.[1857] The AER does not consider that a change from this approach is warranted on the basis of material provided by SKM.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, the AER is not satisfied that SKM's approach provides a realistic expectation of the cost of steel required for Ergon Energy to achieve the capex objectives in the next regulatory control period.

In addition to the issues identified above, the AER considers that to develop a robust forecast it is appropriate to update the forecast materials cost escalators using the most recent data.[1858]

The AER considers that these are the minimum adjustments necessary to ensure that the material cost escalators used by Ergon Energy provide a realistic expectation of movements of the cost of steel over the next regulatory control period.

AER conclusion

Based on the most recent data at the time of this draft decision and the methodology outlined at the end of this appendix, the AER's conclusions on real steel escalators for this draft decision are presented in table H.13.

Table H.13: AER conclusion on real steel cost escalators for Ergon Energy (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Steel	7.1	–29.4	28.6	21.0	4.6	0.6	–0.8

Source: AER analysis.

H.3.2.3 Crude oil

Ergon Energy engaged SKM to develop an escalator for crude oil. This escalator was used to reflect the cost of insulator oil components of capital equipment, not as a proxy for the cost of fuel for transport.

SKM stated that world oil markets provide futures contracts with settlement dates sufficiently far forward to allow their use in forecasting escalation rates for crude oil

1856 http://www.cbo.gov/doc.cfm?index=10521
1857 For example, see AER, *Final decision, NSW DNSPs*, p. 502.
1858 AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.

costs, without the need to refer to Consensus Economics forecasts.[1859] However, in response to questions from the AER, SKM indicated that the futures data it sourced at the time of its review for Ergon Energy was less reliable than normal as a result of volatility caused by the GFC. SKM was particularly concerned about the November 2011 forecast of US$121.12, which was significantly higher than values before and after that month. SKM therefore decided to use only two years of futures prices and long term Consensus Economics prices thereafter.[1860]

Based on this approach, the escalation rates for crude oil that SKM calculated for Ergon Energy are shown in table H.14.

Table H.14: SKM's real crude oil cost escalators calculated for Ergon Energy (%)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Crude oil	–48.2	2.9	15.8	14.0	7.9	9.8	8.4

Sources: Real percentage changes calculated on the basis of SKM's proposed CPI forecasts and commodity forecasts, p. 1 and p. 4 respectively of Ergon Energy, Regulatory Proposal, document PL651c, Electricity Industry Labour, Commodity and Asset Price Cost Indices, January 2009, which replaces the incorrect attachment AR461 by the same title.

H.3.2.4 AER considerations

The AER considers that SKM's approach to forecasting the escalation of Ergon Energy's crude oil costs is similar to the method previously approved by the AER in recent decisions.[1861]

The AER notes that the price of oil futures contracts are available for the duration of the next regulatory control period. As a result, it is not necessary to rely on economic forecasts as an indicator of future oil prices. The AER notes that SKM's preferred approach is to use commodity futures contract prices in preference to economic forecasts, on the basis that:[1862]

- forward contract markets for oil are well established and sufficiently liquid to indicate future prices
- futures contracts represent the stated future position of market participants who have actively placed money behind their individual predictions
- futures contract markets provide greater and more immediate financial risk than economic forecasts that do not involve any direct financial risk to the forecasters.

The AER considers that cost escalators based on futures contract prices alone provide a more accurate indication of future materials costs that escalators based on a combination of futures contract prices and economic forecasts.

1859 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, p. 27.
1860 Ergon Energy, Response to AER question AER.ERG.26.01, 22 October 2010, confidential.
1861 For example, see AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 505–506; and AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.
1862 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, p. 23.

The AER notes that SKM based its estimate of futures contract prices on observations from a single trading day. The AER considers that using a monthly average of NYMEX futures contract prices is more appropriate than using prices from a single day because it removes potential price distortions that may arise on a single day.[1863]

For the reasons discussed, and as a result of the AER's analysis of the regulatory proposal, the AER is not satisfied that Ergon Energy' proposed methodology for forecasting the cost of crude oil reasonably reflects the capex and opex criteria, including the capex and opex objectives. In coming to this view the AER has had regard to the capex and opex factors.

Based on the most recent data at the time of this draft decision and the methodology, the AER's conclusions on the escalation of crude oil costs for this draft determination are presented in table H.15.

Table H.15: AER conclusion on Ergon Energy's real crude oil cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Crude oil	–17.3	–8.3	22.0	15.8	5.5	1.7	0.4

Source: AER analysis.

H.3.2.5 Exchange rates

The SKM cost escalation modelling process makes use of US dollar to Australian dollar exchange rates (USD/AUS) to restate US dollar based market prices of commodities, namely copper, aluminium, steel and oil, into Australian dollar prices.

SKM has used Econtech's ANSIO June 2008 long term forecast for the USD/AUD exchange rate in its cost escalation model.[1864] Based on this approach, SKM's exchange rate forecasts are shown in table H.16.

Table H.16: SKM's exchange rate forecast for Ergon Energy (USD/AUD)

	2008–09	2009–10	20010–11	2011–12	2012–13	2013–14	2014–15
Exchange rate	0.96	0.92	0.86	0.83	0.81	0.78	0.78

Sources: Ergon Energy, *Regulatory Proposal*, attachment AR438, SKM, Electricity Industry Labour, Commodity and Asset Price Cost Indices, p. 32.

AER considerations

The method used by SKM to forecast the USD/AUD exchange rates is similar to that the AER has approved for the NSW DNSPs.[1865] The AER considers that this approach is sound, as it is based on credible views from a range of professional forecasters. As a result, the AER is satisfied that SKM's approach to forecasting

1863 AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.

1864 Econtech report used only provide forecast up to June 2014, the June 2015 period is assume by SKM as simply a continuation of the June 2014 forecast rate.

1865 For example, see AER, *Final decision, NSW DNSPs*, p. 502.

USD/AUD exchange rates reasonably reflects the capex criteria, including the capex objectives.

However, to develop a robust forecast, the AER considers that it is appropriate to update the forecasts using the most recent data.[1866] The AER considers that this is the minimum adjustment necessary for Ergon Energy's exchange rate forecasts to comply with the NER. In coming to this view the AER has had regard to the capex factors.

AER conclusions

Based on its understanding of SKM's methodology, the AER has updated Ergon Energy's forecast USD/AUD exchange rates. These are shown in table H.17.

Table H.17: AER conclusion on exchange rate forecasts for Ergon Energy (per cent)

	2008–09	2009–10	20010–11	2011–12	2012–13	2013–14	2014–15
USD/AUD exchange rate	0.744	0.800	0.656	0.603	0.585	0.581	0.580

Source: AER analysis; Econtech, ANSIO, 20 August 2009, p. 110.

H.3.2.6 Trade weighted index (TWI)

SKM applied the TWI published by the RBA to develop a nominal escalator for Ergon Energy's imported manufacturing input costs, and used this as an input cost component within the cost escalation model. SKM stated that the TWI is utilised as a means to account for the comparative movement in the cost of imported items at the effective Australian dollar exchange rate.[1867]

SKM used the historical TWI published by the RBA to calculate nominal escalation rates for imported manufacturing costs for the period between 2005–2008, and then used a constant TWI of 71 for the calculation of nominal escalation rates for imported manufacturing costs from 2009 until the end of the next regulatory control period. The nominal escalation rates for imported manufacturing costs proposed by SKM are shown in table H.18.

Table H.18: SKM's forecasts of nominal escalation rates for imported manufacturing costs for Ergon Energy

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Nominal escalator for imported manufacturing costs	0.990	0.971	1.014	1.024	1.024	1.024	1.024	1.024	1.024

Sources: Ergon Energy, *Regulatory Proposa*l, July 2009, attachment AR438, SKM, Electricity Industry Labour, Commodity and Asset Price Cost Indices, p. 33.

1866 AER, *Final Decision, ElectraNet*, 11 April 2008, p. 43.

1867 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, p. 15.

AER considerations

The AER notes that it considered a similar proposal in the context of indirect (producer's) labour escalators proposed by ActewAGL Distribution.[1868]

The AER reviewed Ergon Energy's regulatory proposal and supporting documentation. The AER considers that this information does not demonstrate how the TWI escalation factor was applied by SKM in developing Ergon Energy's asset class cost escalators.

The AER and PB requested further information from Ergon Energy to demonstrate the application and weighting of the TWI component within SKM's escalation modelling.[1869] Ergon Energy advised that SKM would not provide that detail as it considered it to be its intellectual property.[1870]

From reviewing the available information, the AER was able to identify a specific weighting of 24 per cent attributed to TWI for the "transport and equipment" cost category.[1871] This appears to be due to a 50 per cent TWI weighting applied to Ergon Energy's fleet expenditure, adjusted for depreciation.[1872]

However, it is not clear how SKM has applied and weighted the TWI escalator in developing Ergon Energy's other asset class escalators.

The AER notes that the proposed TWI component appears to produce negative real escalation rates for the years 2006–07 and 2007–08.[1873] In isolation, this outcome may appear to reconcile with the real decreases in raw materials costs such as steel, copper and aluminium, observed around this time. However, as Ergon Energy has not been able to demonstrate the application of the TWI escalation component, the AER cannot confirm its impact elsewhere in the modelling, or whether the assumptions underpinning its application are reasonable. As a result, the AER is not satisfied that Ergon Energy's proposed inclusion of a TWI component in its real cost escalations reasonably reflects the opex or capex criteria, including the opex and capex objectives.

[1868] AER, *Final decision, ACT DNSP*, 28 April 2009, pp. 45–46. In its final decision for ActewAGL Distribution, the AER rejected the application of a TWI adjusted CPI escalation for the labour components of imported manufactured plant and equipment. It considered that SKM and ActewAGL had not demonstrated that its assumed labour cost growth rates were a realistic expectation of those expected to be incurred by manufacturers in the relevant exporting countries.

[1869] AER, request for information, AER.ERG.15.12, 8 September 2009; and PB, request for information, PB.ERG.JH.01.

[1870] Ergon Energy, email response to PB.ERG.JH.01, 29 August 2009, confidential.

[1871] Ergon Energy, response to Q.AER.ERG.15.12, 18 September 2009, confidential (PL849c - SKM, Mapping the established SKM drivers of cost escalation to Ergon Energy escalation factors. 2 December 2008. p. 16; and PL848c – Escalations sources reference years materials, 17 September 2009).

[1872] Ergon Energy, response to Q.AER.ERG.15.12, 18 September 2009, confidential, 2 December 2008, p. 15.

[1873] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity Industry Labour, Commodity and Asset Price Cost Indices – Stage 2, 6 October 2008, p. 33.

AER conclusions

The AER considers that Ergon Energy's escalation modelling should be adjusted to remove any weighting of TWI components, including those applied to imported manufactured equipment, and is the minimum adjustment necessary for this element of the opex proposal to comply with the NER. In coming to this view the AER has had regard to the opex and capex factors.

H.3.2.7 Inflation rate

Inflation forecasts are needed to convert forecasts of materials prices from nominal terms into real terms.

Ergon Energy's consultant SKM considered the CPI forecasts from CEG's April 2008 report to the AER to be the most recent and credible forecasts of inflation available.[1874] Ergon Energy applied these forecasts to derive nominal values for all cost elements not covered by materials or labour cost escalators.[1875]

Based on this approach, the inflation rate forecasts used by Ergon Energy in its cost escalation model are shown in table H.19.

Table H.19: SKM's inflation rate forecasts (annual June to June percentage change)

	2008–09	2009–10	20010–11	2011–12	2012–13	2013–14	2014–15
Inflation rate	2.8	2.4	2.4	2.5	2.5	2.4	2.5

Sources: Ergon Energy, Regulatory Proposal, attachment AR438, SKM, Electricity Industry Labour, Commodity and Asset Price Cost Indices, p. 32.

AER considerations

The AER considers the inflation outlook has changed significantly since the publication of CEG's forecast in April 2008. As a result, the AER has concerns about the use of CEG's inflation rate forecasts by Ergon Energy.

In the absence of more recent forecasts from CEG, the AER considers that the RBA's quarterly statement on monetary policy is an independent and credible source of inflation forecasts. The AER also considers that inflation forecasts for the remainder of the regulatory control period beyond the RBA forecast should be established by interpolating the RBA forecasts using an annual inflation rate of 2.5 per cent (being the mid–point of the RBA inflation target band of 2 to 3 per cent). This approach is consistent with the AER's recent decision for the ACT and NSW DNSP's.[1876] The AER also considers that this approach should be adopted to ensure that consistent approaches to inflation rate forecasts are used for real cost escalators and the PTRM.

[1874] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR461, SKM, Electricity industry labour, commodity and asset price cost indices, 14 January 2009, p. 32.

[1875] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR461, SKM, Electricity industry labour, commodity and asset price cost indices, 14 January 2009, p. 46.

[1876] For example, see AER, *Final decision, NSW DNSPs*, pp. 478–507 and AER, *Final Decision, ElectraNet*, 11 April 2008, pp. 29–48.

AER conclusion

Based on the most recent data at the time of this draft decision and the methodology outlined at the end of this appendix. The AER's conclusions on inflation rate forecasts for this draft determination are presented in table H.20.

Table H.20: AER conclusion on inflation rate forecasts for Ergon Energy (June to June, per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Inflation rate	1.5	2.7	2.0	2.5	2.5	2.5	2.5

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, the AER is not satisfied that Ergon Energy's proposed methodology for forecasting inflation reasonably reflects the capex and opex criteria, including the capex and opex objectives. In coming to this view the AER has had regard to the capex and opex factors.

H.3.2.8 Land and easements

Ergon Energy obtained advice from SKM on forecast movements of land prices in Queensland. SKM determined no credible long term forecasts exist for land prices and that available historical data was insufficient to capture the nuances associated with cyclic trends in land and property values.[1877]

SKM considered the use of the average historical growth factors over the longest available period for Queensland land values, based on ABS data, should be considered a reasonable assumption of the likely movements in land costs.[1878]

Based on ABS data from June 1990 to June 2007, SKM calculated the following historical average growth rates in nominal Queensland land values:[1879]

- residential: 12.7%
- commercial: 8.1%
- rural: 10.8%
- other: 7.6%
- total: 11.2%.

[1877] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, p. 38.

[1878] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, p. 41.

[1879] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, table 15, p. 41.

The AER notes that Ergon Energy has only applied SKM's escalation rates for the rural and commercial land categories, based on the composition of its forecast capex program.[1880] SKM's recommended land and easement escalators are set out in table H.21.

Table H.21: SKM real forecast land and easement escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Commercial	4.2	5.5	5.4	5.0	5.0	5.4	5.8
Rural	6.8	8.1	8.0	7.6	7.6	8.0	8.4

Source: Ergon Energy, *Regulatory Proposal*, document PL651c, Electricity industry labour, commodity and asset price cost indices, January 2009.

Note: These rates do not reconcile with those presented by Ergon Energy on p. 336 of its Regulatory proposal, which are rebased, nominal and cumulative adaptations of the above rates for Ergon Energy's modelling purposes. For transparency, the AER presents the real, annual escalators developed by SKM.

AER considerations

SKM and Ergon Energy's use of historical average data is generally consistent with the AER's approach to testing the reasonableness of previously proposed land price escalators.[1881]

To test the reasonableness of SKM's proposed land price escalators, the AER analysed Queensland land value data published by the ABS, using its entire data series (1989–2008). The AER derived long term historical growth rates for Queensland land types published by the ABS (residential, commercial and rural). These were then deflated by Brisbane CPI to calculate real growth rates.[1882] This analysis indicated that SKM's nominal average historical growth rates appear reasonable.

The AER notes that since preparation of SKM's estimates, land value observations for the year ending June 2009 have been released.[1883] However, the inclusion of these additional observations has no material impact the calculated historical average growth rate.

Based on the long term historical growth in Queensland land values published by the ABS, the AER considers that SKM an Ergon Energy's proposed land and easement escalators are reasonable.

[1880] Ergon Energy, email response to Q.AER.ERG.08.9, 29 August 2009, confidential.

[1881] For example, AER, *Final decision, NSW DNSPs*, pp. 542–543; AER, *Final Decision, ElectraNet*, 11 April 2008, p. 34; AER, *Draft Decision, SP AusNet*, 31 August 2007, pp. 189–190; and AER, *Draft decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 8 December 2006, p. 76.

[1882] ABS, Cat No. 6401.0, *Consumer Price Index*, Australia, Table 14, ID: A2325817T.

[1883] ABS, Cat No. 5204.0 *Australian System of National Accounts*, Table 61. Value of Land, by Land use by State/Territory - as at 30 June, Current prices.

AER conclusions

The AER's conclusions on forecast land and easement escalators are set out in table H.22.

For the reasons discussed and as a result of the AER's analysis of Ergon Energy's regulatory proposal and supporting information, the AER is satisfied that Ergon Energy's land and easement growth rates reasonably reflect the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Table H.22: AER conclusion on Ergon Energy's real land and easements escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Commercial	4.2	5.5	5.4	5.0	5.0	5.4	5.8
Rural	6.8	8.1	8.0	7.6	7.6	8.0	8.4

Source: Ergon Energy, *Regulatory proposal*, July 2009, PL651c, Electricity Industry labour, commodity and asset price cost indices, January 2009.
Note: The AER will expect Ergon Energy to apply the AER's updated inflation forecasts to deflate its nominal land escalators for its final decision.

H.3.2.9 Construction costs

SKM included construction costs in its model as a key driver underlying network project costs to account for increases in both labour and materials elements of both civil works or components of electricity network capex projects.[1884]

SKM adopted the CFC's engineering construction costs[1885] forecast going forward as the likely movements in the construction cost component of relevance to Ergon Energy within its cost escalation model.[1886]

SKM applied the latest available forecasts of construction costs at the time of publishing its report. SKM's construction costs forecasts are shown in table H.23.

Table H.23: SKM nominal construction and building cost growth rates (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Construction Costs	4.7	2.5	4.6	4.4	2.5	1.1	1.8

Source: SKM, Electricity industry labour, commodity and asset price cost indices – January 2009 update of escalators, 14 January 2009, p. 3.

[1884] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, p. 21.
[1885] SKM considers this forecast appropriate, given the CFC considers electricity and pipeline construction to fall within the 'engineering' construction costs sector.
[1886] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, pp. 22–23.

AER considerations

The AER notes SKM applied engineering construction cost forecasts sourced from the CFC's website, which is consistent with the application of construction cost forecasts in the AER's ACT and NSW final electricity distribution determinations.[1887] Given recent fluctuations in economic conditions, the AER considers it reasonable to apply the updated CFC construction cost forecasts as they reflect the most recent data available.[1888] The AER deflated the updated engineering construction cost forecasts using Econtech's ANSIO inflation forecasts to determine real forecasts.[1889] The AER considers these updated forecasts reflect a reasonable expectation of movements in the sector over the next regulatory period and will therefore apply the updated CFC construction cost forecasts for this draft decision.

AER conclusion

The AER's conclusions on forecast real construction cost escalators are set out in table H.24.

Table H.24: AER conclusion on Ergon Energy's real construction cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Construction Costs	2.8	1.1	–0.9	–0.2	1.0	0.0	–1.5

For the reasons discussed and as a result of the AER's analysis of Ergon Energy's regulatory proposal, the AER is not satisfied that Ergon Energy's construction cost forecasts reasonably reflect the capex and opex criteria, including the capex and opex objectives. The AER considers Ergon Energy's construction cost escalators should be adjusted to reflect the latest available forecasts produced by the CFC, and is the minimum adjustment necessary for Ergon Energy's construction cost escalators to comply with the NER. In coming to this view, the AER has had regard to the capex and opex factors.

H.3.2.10 Building Costs

Ergon Energy sought advice from SKM to develop forecast building costs escalators. SKM analysed ABS data and sought additional information from a range of organisations to determine a forecast for building costs. SKM considered that insufficient publicly available historical data, or forecasts, existed to derive a relevant escalator. In the absence of a reputable forecast, SKM considered it reasonable to assume that building costs will escalate at least in line with the rate of growth in

[1887] AER, *Final decision, NSW DNSPs*, 28 April 2009; and AER, *Final decision, ACT DNSP*, 28 April 2009.

[1888] The AER accessed the CFC's published May 2009 forecasts on 14 September 2009.

[1889] Econtech, *Australian National State and Industry Outlook*, 20 August 2009, p. 110. Econtech's annual CPI movements measure the percentage change of the average prices of a constant basket of goods and services over two consecutive financial years.

construction costs. Therefore, SKM applied its construction cost escalator (developed by CFC) as a proxy for building costs, as shown in table H.25.[1890]

Table H.25: SKM nominal construction and building cost growth rates (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Construction Costs	4.7	2.5	4.6	4.4	2.5	1.1	1.8

Source: SKM, *Electricity Industry Labour, Commodity and Asset Price Cost Indices – January 2009 Update of Escalators*, 14 January 2009, p. 3.

AER considerations

The AER notes that SKM considered insufficient robust data existed to forecast building cost escalators. Consequently, Ergon Energy applied the construction cost forecast, developed by CFC, as a proxy for a building cost escalator.

The AER considers Ergon Energy's approach to apply the CFC's construction cost forecasts as a proxy for a building cost escalator as reasonable, particularly as, the AER notes, construction cost forecasts are derived from the ABS data.[1891]

As discussed in section H.3.2.9, the AER is not satisfied Ergon Energy's proposed escalators reasonably reflect latest expectations of forecast construction costs. Therefore, the AER has applied the CFC's updated engineering construction cost forecasts as at June 2009, deflated by the most recent ANSIO inflation forecasts.[1892]

AER conclusion

The AER's conclusions on forecast real buildings cost escalators are set out in table H.24.

For the reasons discussed and as a result of the AER's analysis of Ergon Energy's regulatory proposal, the AER is not satisfied that Ergon Energy's buildings escalators reflect the capex and opex criteria, including the capex and opex objectives. The AER considers Ergon Energy's buildings escalators should be adjusted to reflect the latest available forecasts produced by the CFC, and is the minimum adjustment necessary for Ergon Energy's buildings escalators to comply with the NER. In coming to this view, the AER has had regard to the capex and opex factors.

H.3.3 AER approach to calculating key materials cost escalators

Aluminium and copper

Cost escalators for aluminium and copper are based on LME spot prices up to the most recent month. The AER then uses a linear interpolation between the LME spot

[1890] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR438, SKM, Electricity industry labour, commodity and asset price cost indices – Stage 2, 6 October 2008, pp. 43–44.

[1891] ABS, Cat No. 8762.0, *Engineering Construction Activity*; and ABS Cat No. 8752.0, *Building Activity*. Details of CFC's forecasts and methodology are available at <http://www.cfc.acif.com.au/analysis2.asp>.

[1892] Econtech, *Australian National State and Industry Outlook*, 20 August 2009, p. 110.

price and the LME forward contract price for aluminium and copper for the periods 3 months, 15 months, 27 months, 63 months and 123 months.[1893]

The forecast aluminium and copper prices from LME are in nominal USD terms. The interpolated series are converted to nominal AUD through the use of the Econtech ANSIO exchange rate forecast. The figures are then converted to real forecast mineral prices using the Australian inflation forecast, as discussed in section H.3.2.7.

The resulting data series represents the monthly materials price that is used to account for base months. These monthly prices are then converted to a yearly average for each financial year. This approach results in less volatility than can occur using only values for the last month of each year to determine annual changes. This is the index used to escalate aluminium and copper prices over the next regulatory control period.

Steel

The cost escalator for steel is based on historical data from Bloomberg for hot rolled coiled steel contract prices in Europe and the United States. The AER then interpolates these actual steel prices with Consensus Economics steel forecasts for Europe and the US.

The US steel prices are then adjusted for volume, as they are in short-tonnes and must be converted to metric tonnes. The long term Consensus Economics forecast price is estimated to be for the period of 5 to 10 years. The AER takes the mid–point (7.5 years) and interpolates from Consensus Economics short term forecast prices to its long term steel prices. The long term steel price is also converted from real to nominal USD by the US Congressional Budget Office inflation forecast. All other Consensus Economics forecasts are already in nominal terms.

The interpolated series is then averaged between Europe and US prices and then converted to nominal AUD through the use of the Econtech ANSIO exchange rate forecast. The figures are then converted to real forecast mineral prices using the Australian inflation forecast discussed in section H.3.2.7. The resulting data series represents the monthly materials price index that is used to account for base months.

The resulting data series represents the monthly materials price that is used to account for base months. These monthly prices are then converted to a yearly average for each financial year. This approach results in less volatility than can occur using only values for the last month of each year to determine annual changes. This is the index used to escalate steel prices over the next regulatory control period.

Crude oil

The cost escalator for crude oil is based on West Texas Intermediate average monthly prices from the United States Department of Energy – Energy Information Agency. The AER interpolates this with Bloomberg forecast crude oil contract prices that use West Texas Intermediate crude oil prices as its reference price.

[1893] The LME 63 month and 123 month forward contract prices are closing prices which are sourced from Bloomberg.

The interpolated series is then converted to nominal Australian dollars through the use of the Econtech ANSIO exchange rate forecast. The figures are then converted to real forecast prices and the resulting data series then represents the monthly crude oil index that is used to account for base months.

The resulting data series represents the monthly materials price that is used to account for base months. These monthly prices are then converted to a yearly average for each financial year. This approach results in less volatility than can occur using only values for the last month of each year to determine annual changes. This is the index used to escalate crude oil prices over the next regulatory control period.

Exchange rates

Historical exchange rates from the RBA are interpolated with Econtech ANSIO exchange rates to convert materials forecasts and prices from USD to AUD.

Inflation

The inflation series used to convert nominal materials series into real terms is based on the consumer price index from the ABS. This series is then interpolated with the RBA's two year CPI forecasts from the Statement on Monetary Policy. This series is further interpolated with a 2.5 per cent per year inflation rate (which is the mid–point of the RBA's 2 per cent to 3 per cent inflation band) for the remainder of the regulatory control period. This is consistent with the AER's approach in other elements of its decision.

In general, the AER attempts to maintain consistency between any forecast nominal series and the consistent inflation forecast within its real cost escalation model.

This index is used to increase all elements of the cost escalators that are not covered by materials or labour escalators. This includes wood poles, information technology systems, office equipment and motor vehicles.

H.4 Labour cost escalators

This section discusses the real labour cost escalations proposed by the Qld DNSPs to apply to their forecast capex and opex allowances in the next regulatory control period.

H.4.1 Qld DNSPs regulatory proposals

H.4.1.1 Energex

Energex engaged KPMG to provide advice on forecast annual internal and contractor labour escalation rates for the period 2007–2025.

KPMG's approach to forecast labour escalation rates was based on a combination of qualitative and quantitative assessments. KPMG determined the following quantitative measures as the most appropriate to forecast its labour escalation rates:[1894]

[1894] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, pp. 2 and 31–33.

- simple moving average (SMA) estimation
- classical regression analysis
- STS analysis.

KPMG considered the SMA approach as appropriate based on its literature review, which showed that the AER previously accepted this as an appropriate methodology.[1895] KPMG applied the effects of a three–yearly enterprise bargaining agreement (EBA) in the moving average estimation methodology.[1896]

KPMG employed regression analysis to develop the most appropriate relationship between variables. Classical regression analysis employed wages as the dependent variable and independent variables included sectoral employment and labour force participation. Based on the estimated equation, the dependent variable was estimated from forecast values of the independent variable. KPMG noted that, in general, classical regression analysis was limited in its applicability to forecasting labour (and contractor) escalation factors.[1897]

The final method employed by KPMG was STS modelling. KPMG considered the application of this method as most appropriate as it provided more robust forecasts, given it more rigorously accounted for the variability in the historical data, compared with KPMG's other methodologies.[1898]

KPMG based its labour escalation rates on a composite index of wage data[1899] from the mining, EGW and construction sectors. Each was equally weighted in deriving the composite index.[1900]

Internal labour costs

KPMG defined internal labour as wages which are determined in Energex's EBA.

KMPG estimated labour escalation rates would range between 1.3 to 10.3 per cent in nominal terms in the next regulatory control period. KPMG considered this range to be consistent with previous regulatory submissions and decisions. KPMG took an equally weighted average of the mid–point results of its three quantitative methods to determine a 'reasonable point estimate' of 5.5 per cent (nominal). Energex applied

[1895] Energex, response to AER.EGX.07.04, 24 September 2009, p. 5.
[1896] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, p. 22. KPMG noted the application of EBA effects could not be replicated for its alternate methodologies given the specifications of the regression equations.
[1897] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, pp. 37, 44; and Energex, response to AER.EGX.07.04, 24 September 2009, pp. 6–7.
[1898] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, pp. 2, 35 and 37. For further detail of KPMG's structural time series modelling, refer to Appendix B.
[1899] ABS, Labour Price Index, Australia, Catalogue Number 6345.0. See: www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/6345.0Jun%202009?OpenDocument
[1900] KPMG, *Escalation rates for labour, materials and contractors*, March 2008, p. 37.

this escalation rate to its internal labour cost forecasts, for each year of the next regulatory control period.[1901]

Contract labour

KPMG defined external labour costs (that is contract labour costs) as wages that are not determined by Energex's EBA.[1902]

KPMG applied a similar approach to develop a contract labour cost escalator, as that used to determine Energex's internal labour cost escalator. KPMG utilised the same data set used to derive its EGW wage forecasts, but did not incorporate EBA rates to derive a contract labour cost escalator. KPMG considered this approach as reasonable, given labour is the primary input into the work undertaken by contractors.[1903]

KMPG estimated contract labour cost escalation rates ranging between 1.3 and 10.3 per cent in nominal terms and derived a reasonable point estimate of 5.5 per cent (nominal), which Energex applied to its contract labour cost forecasts, for each year of the next regulatory control period.[1904]

Energex's proposed internal and contract labour cost escalators (real) are shown in table H.26.

Table H.26: Energex's proposed real labour cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Internal labour	2.03	3.05	3.05	3.05	3.05	3.05	3.05
Contract labour	2.03	3.05	3.05	3.05	3.05	3.05	3.05

Source: Energex, response to, AER.EGX.26, 5 October 2009.

H.4.1.2 Ergon Energy

Ergon Energy developed cost escalation factors to be applied to internal labour and contractor cost inputs for its opex forecasts from 2008–09 to 2014–15.

Ergon Energy noted its internal labour costs have been escalated by an increment based on its 2008 Union Collective Agreement of 4.5 per cent, per annum, plus an additional EDSD Review technical or professional allowance increment that is payable to Ergon Energy staff, which ceases in 2010–11.[1905]

1901 KPMG, *Escalation rates for labour, materials and contractors*, March 2008, pp. 35–37 and Energex, response to AER.EGX.07.07, 24 September 2009, p. 11.
1902 KPMG, *Escalation rates for labour, materials and contractors*, March 2008, p. 4.
1903 KPMG, *Escalation rates for labour, materials and contractors*, March 2008, p. 42.
1904 KPMG, *Escalation rates for labour, materials and contractors*, March 2008, pp. 36, 42.
1905 Ergon Energy, *Regulatory Proposal*, July 2009, p. 330; and Ergon Energy, request for information (Q.AER.ERG.15.3), 18 September 2009.

Ergon Energy also escalated its contract labour costs at the same rate as its internal labour.[1906] Ergon Energy further noted that all contractor rates have been escalated by an increment based on its Union Collective Agreement 2008, which specifies a requirement that contractor staff rates are indexed to Ergon Energy's staff rates.[1907] Ergon Energy's proposed labour cost escalators are shown in table H.27.

Table H.27: Ergon Energy's proposed nominal labour cost growth rates (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Internal labour	5.1	5.1	4.4	4.5	4.5	4.5	4.6
Contract labour	5.1	5.1	4.4	4.5	4.5	4.5	4.6

Source: Ergon Energy, *Regulatory Proposal*, July 2009, p. 336.

Ergon Energy also engaged SKM to develop cost escalation factors for its capex asset categories for the next regulatory control period.[1908] Ergon Energy advised the AER that SKM applied Ergon Energy's proposed labour escalators in deriving these specific capex escalators.[1909]

H.4.2 Submissions

Origin noted Energex's revisions to its contracting strategy and requested further detail, including whether cost impacts will result from the revised strategy and the remuneration equivalency between internal and external labour.[1910]

H.4.3 Consultant review

The AER engaged Access Economics to provide growth forecasts for EGW (Utilities) and general state labour price indices (LPIs) for NSW, Victoria, Queensland, South Australia, ACT and nationally.[1911]

The macroeconomic forecasts prepared by Access Economics were developed using a formal econometric modelling approach (Access Economics macro model – AEM). The wage forecasting methodology applied by Access Economics involves estimating deviations between industry, state-specific, and broad measures of wages in the Australian economy.[1912]

Access Economics noted that its modelling of specific LPIs begins with movements in the total Australian LPI. From this index, the AEM adds in deviations from the

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[1906] Ergon Energy, request for information (Q.AER.ERG.08.3), 2 September 2009.
[1907] Ergon Energy, *Regulatory proposal*, July 2009, p. 336.
[1908] SKM, *Electricity Industry Labour, Commodity and Asset Price Cost Indices – Stage 2*, 6 October 2008; and SKM, *January 2009 Update of Escalators*, 14 January 2009.
[1909] Ergon Energy, response to Q.AER.ERG.15.09, 18 September 2009.
[1910] Origin, *Queensland DNSPs*, 28 August 2009, p. 7.
[1911] Access Economics, *Forecast growth in labour costs*, 16 September 2009.
[1912] Access Economics, Forecast growth in labour costs, 16 September 2009, appendix C, p. 104

average. Access Economics noted three key factors driving wage differentials which are incorporated into its modelling:[1913]

- business cycle factors – the model considers how fast the industry/State is growing relative to the national and historical averages
- productivity factors – the model uses an average of productivity trends across the past two years
- competition (relative wage) factors – the modelling approach sees wages in competitor industries moving closer together.

Access Economics noted the importance of judgement when determining movements in wages, particularly in current circumstances where data volatility and the effects of factors, not relevant to wage determination, on broader output and employment measures exist.[1914]

In deriving its forecasts, Access Economics applied a concordance table to reclassify the LPI estimates to align with the ABS' updated Australian and New Zealand Standard Industry Classifications (ANZSIC) structure.[1915]

Utilities sector LPI – Electricity Gas and Water

Access Economics noted that, as a result of the jobs boom in the 2000s, the utilities sector (at a national level) was in competition for skilled labour with other key sectors. This has resulted in utilities sector wages growing faster than overall national wages growth.[1916]

The recent downturn in the Australian economy has affected the utilities sector and other sectors which would normally compete for workers. Access Economics noted there have been substantial job losses in the manufacturing and mining sectors, while the share of Australian workers in the construction industry is expected to weaken in 2010. Access Economics has also forecast business demand to weaken with the utilities sector expected to suffer the short term weaknesses before recovering to usual growth rates. This is reflected within the national utilities LPI forecasts, where the projected trends over the next regulatory control period illustrate moderate growth relative to national mining, construction and manufacturing sectors wage growth forecasts.[1917] Access Economics stated that it expects wage growth in the utilities sector to be weak in the short term, before recovering to its usual growth rate, averaging slightly below that of the wider Australian economy.[1918]

[1913] Access Economics, *Forecast growth in labour costs*, 16 September 2009, appendix C, pp. 104–105.
[1914] Access Economics, *Forecast growth in labour costs*, 16 September 2009, appendix C, p. 105.
[1915] Access Economics, *Forecast growth in labour costs*, 16 September 2009, appendix C, p. 114.
[1916] Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. 31.
[1917] Access Economics, *Forecast growth in labour costs*, 16 September 2009, pp. 34–35.
[1918] Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. 34.

Over the next regulatory control period, Access Economics has forecast average annual growth for the national utilities LPI of 1.1 per cent (real). In comparison, the forecast average annual growth rate for the Queensland utilities sector LPI is expected to be slightly lower at 1.0 per cent (real).[1919]

Access Economics made the following observations on Queensland's EGW sector:[1920]

- the underperformance in the wider State economy is yet to be reflected in movements in EGW wages
- demand for the EGW workers (and the types of workers employed) is slowing, resulting in slower wages growth
- however supply side developments foreshadow additional demand for EGW workers in the future.

Due to a weakening State economy and weakening demand from competitor sectors, Access Economics considered Queensland's EGW sector will see moderate wage growth rates until mid–2011 before trending upwards thereafter.[1921] Access Economics' EGW labour cost forecasts are set out in table H.28 below.

Table H.28: Access Economics real labour escalation rates for the EGW sector in Queensland and Australia (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Queensland	0.9	1.5	0.1	0.6	1.2	1.6	1.5
Australia	1.4	1.6	0.4	0.6	1.1	1.6	1.7

Source: Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. xiv.

State All Industries LPI - General labour

Access Economics considered that, in the current market, there is an expectation for general wages growth to ease. Access Economics noted the national all industries LPI fell below 4 per cent (nominal) over the past year and further expects overall future wages growth to ease further. Access Economics noted that wage growth has moderated in sectors suffering from the recent economic downturn, while gains in well protected areas are also evident.[1922]

Access Economics forecasts national general labour cost growth to ease to 3.5 per cent nominal in 2010, before rising in 2011 and continuing with moderate growth for the remainder of the next regulatory control period.[1923]

[1919] Access Economics, *Forecast growth in labour costs*, 16 September 2009, pp. 48, 66.
[1920] Access Economics, *Forecast growth in labour costs*, 16 September 2009, pp. 66–68.
[1921] Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. 68.
[1922] Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. 27.
[1923] Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. 29.

Access Economics made the following observations on Queensland economy, impacting its general labour cost growth forecasts:[1924]

- Queensland suffered considerably in the recent economic slowdown, particularly due to negative impacts on the States mining and tourism sectors
- economic growth is expected to slow in the next 18 months
- reductions in output growth will impact labour cost growth rates.

Access Economics projected general labour cost growth rates in Queensland to slow to 3 per cent (nominal) in the next year before broadly aligning with the projected national average from mid–2011.[1925] Access Economics' general labour cost growth forecasts are shown in table H.29.

Table H.29: Access Economics real general labour escalation rates for Queensland and Australia (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Queensland	0.4	0.9	0.2	0.6	1.0	1.5	1.5
Australia	0.9	1.7	0.9	0.9	1.1	1.6	1.8

Source: Access Economics, *Forecast growth in labour costs*, 16 September 2009, pp. 48, 90.

H.4.4 AER considerations

H.4.4.1 Energex

The AER has examined the labour escalation rates put forward by KPMG for Energex and the methodologies used to derive the forecasts. While the AER considers that KPMG's general approach appears rigorous, it has a number of concerns with applying the outputs of KPMG's modelling.

First, the economic climate has changed since KPMG's forecasts were derived. The AER does not consider KPMG's forecasts are based on the most recently available data and are therefore unlikely to represent a best estimate of future labour costs.

Second, the AER does not consider the application of a constant labour cost growth rate for the duration of the next regulatory control period is reasonable. The AER considers that assuming a constant growth forecast does not accurately reflect the volatility and uncertainty of market conditions. On this basis, it is unlikely to represent a reasonable expectation of growth in labour costs during each year of the next regulatory control period.

The AER considers that it is appropriate to apply forecasts based on the latest available data. Therefore, the AER will apply the Access Economics labour cost growth forecasts for Queensland as produced in September 2009, to Energex's

[1924] Access Economics, *Forecast growth in labour costs*, 16 September 2009, pp. 92–93.
[1925] Access Economics, *Forecast growth in labour costs*, 16 September 2009, p. 93.

forecast labour costs. The AER also considers it appropriate to further update these forecasts for the purposes of its final decision.

Application of the forecasts

The AER notes that Energex's labour cost escalators do not provide for specific escalation rates to apply to the different types of labour resources it is expected to require during the next regulatory control period. Specifically, in applying its proposed labour escalators, Energex does not distinguish between specialist electrical labour resources, and general labour resources. Given that the AER is allowing real cost escalation for this distribution determination, the AER sees this as an important consideration. These two labour categories have historically exhibited some wage growth differentials and this characteristic is forecast to remain, albeit less pronounced, during the early years of the next regulatory control period.[1926] The AER considers that an appropriate internal labour cost escalator should consider these factors.

The AER notes that KPMG has used a variety of data sources to capture differences in relative labour cost growth rates, however, it is not clear that these assumptions accurately reflect Energex's own labour resource needs for the next regulatory control period.

EGW and general labour escalators

The AER requested further information from Energex regarding the composition of its internal labour force to establish the relative contribution of specialised and general labour resources to its forecast expenditure programs. In response, Energex undertook a high level assessment of base labour hours included in direct system capital and operating expenditure works and submitted the following categorisation of its internal staff as general labour resources:[1927]

- project managers
- mechanical engineers
- procurement engineers
- community liaison officers
- property officers
- corporate communications officers
- data entry, clerical and other support officers.

The AER notes that these labour costs account for approximately 5 per cent of Energex's forecast system capital and operating expenditure.[1928]

[1926] See, Access Economics, Forecast growth in labour costs, 16 September 2009, p. 68.
[1927] Energex, response to AER.EGX.27.01, 5 October 2009, confidential.
[1928] Energex, response to AER.EGX.27.01, 5 October 2009, confidential.

Energex also provided details of its specialist electrical industry labour resources. Energex submitted that it has assumed that its specialist electrical industry employees include:[1929]

- qualified electricians and/or electrical engineers
- non-qualified workers who have undertaken additional specialist training to satisfy jurisdictional and legislative requirements to complete work on or near the distribution network, which is beyond similar work undertaken in the construction industry.

Energex submitted that the work undertaken by its specialist electrical industry labour resources include:

- design work, including; distribution, transmission, mains, substation, supervisory control and data acquisition (SCADA) and concept design
- distribution and transmission overhead and live line works, and underground works
- customer connections work
- network switching
- SCADA, field test, protection and telecommunications work
- reliability and maintenance planning
- capability planning
- development of technical standards.

Energex submitted that these labour costs account for around 95 per cent of Energex's forecast system capital and operating expenditure attributable to labour.[1930]

The AER considers the specialist positions described by Energex reasonably reflect specialist EGW labour resources.[1931] The remaining 5 per cent of Energex's internal labour resources are employed in roles that the AER considers are consistent with general labour resources, rather than specialist electrical labour.

Based on information provided by Energex, the AER considers it is not appropriate to apply a single labour escalation rate to forecasts expenditures that does not reflect the different types of labour resources to be used, and the potential for differentials in the expected costs of those labour resources. The AER considers that an appropriate labour cost escalator should consider these factors. Therefore, the AER will apply a weighted average labour cost escalator should to Energex's internal labour cost

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[1929] Energex, email response to AER.EGX.27. 5 October 2009, confidential.
[1930] Energex, email response to AER.EGX.27.01, 5 October 2009, confidential.
[1931] The AER considers EGW employees as specialist electrical industry employee undertaking direct project work.

forecasts (for opex and capex), based on the relative contribution of specialist EGW and generic labour resources.

The AER will observe the actual EBA rate increase incurred by Energex in 2008–09, including an appropriate adjustment in 2010–11 to reflect the impact of the AER's indexing approach.

The AER has calculated a weighted labour escalator based on Energex's internal labour resources being estimated at 95 per cent specialist EGW labour, and 5 per cent general labour types. These proportions were used to weight the respective general and EGW labour cost forecasts developed by Access Economics, as discussed in section H.4.3. The AER's weighted average labour escalators for Energex's forecast internal labour costs are set out at table H.30.

Table H.30: AER weighted average internal labour escalators for Energex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
AER real weighted average internal labour escalator	–0.03	2.51	0.69	0.57	1.20	1.56	1.54

Source: AER analysis; Access Economics, *Forecast growth in labour costs*, 16 September 2009.

Contract labour

Consistent with its approach to escalating internal labour resources, Energex has applied KPMG's (EGW) labour escalation rates to its forecast external (contractor) labour costs for the next regulatory control period.

The AER considers KPMG's general recommendation to apply a measure of forecast wages growth to escalate Energex's contract labour as reasonable. However, as discussed above, it does not consider KPMG's labour cost forecasts are reasonably supported or justified.

In considering Energex's proposed contract labour escalators, the AER sought further information from Energex to establish the type of labour reflected in its contract labour forecasts. In response, Energex undertook a high level assessment of its resources and categorised its contractor resources as follows:[1932]

- industry specialist contractors – qualified electricians and/or electrical engineers with specialised industry training, and non-qualified contractors with specialised industry training, representing approximately 79 per cent of its forecast contract labour expenditure

- generic contractors – non-qualified contractors with no formal, specialised training, representing approximately 21 per cent of its forecast contract labour expenditure.[1933]

[1932] Energex, response to AER.EGX.14, received 25 September 2009, p. 3, confidential.
[1933] Energex further noted normal site and safety induction, and electrical awareness training are not considered to be formal specialised training.

The AER considers that the job descriptions identified by Energex as specialist electrical industry contract labour can be reasonably categorised as EGW labour resources. The AER therefore considers it reasonable to apply EGW labour escalation forecasts to Energex's forecast specialist electrical industry contract labour costs. The AER notes that these labour costs account for approximately 79 per cent of Energex's forecast system capital and operating expenditure.[1934]

The EGW forecasts that the AER has applied to Energex's specialist contract labour will not include any EBA rate adjustments for the current regulatory control period. The AER does not consider it reasonable to apply EBA rates to contractors, as they do not form part of the internal workforce to which the award must apply. This approach is consistent with KPMG's approach to developing contract labour escalators.[1935]

Regarding Energex's generic contract labour forecasts, the nature of Energex's generic contract labour indicates that these workers are likely to represent general, rather than specialist EGW labour resources. The AER considers the general labour wage forecast is an appropriate measure to escalate direct general labour costs (that is, other than EGW labour) incurred by DNSPs. Therefore, the AER considers it reasonable to apply a general labour growth forecast to Energex's generic contractor labour costs.

The AER considers that an appropriate labour cost escalator should consider the composition of Energex's forecast contract labour requirements. Therefore, the AER considers a weighted average cost escalator should be applied to Energex's contract labour cost forecasts (for opex and capex), based on the relative contribution of specialist EGW and generic contract labour resources to the forecast expenditure programs. The AER's has calculated a weighted average contract labour escalator based on Energex's contracted labour resources being estimated at 79 per cent specialist EGW, and 21 per cent general contract labour types, and derived using respective labour cost forecasts developed by Access Economics as discussed in section H.4.3. The AER's weighted average labour escalators for Energex's forecast contract labour costs are set out at table H.31.

Table H.31: AER weighted average contract labour escalators for Energex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
AER real weighted average contract labour escalator	0.77	1.38	0.14	0.58	1.17	1.54	1.53

Source: AER analysis; Access Economics, Forecast growth in labour costs, 16 September 2009.

H.4.4.2 Ergon Energy

The AER notes Ergon Energy's forecast labour cost escalation rates are based on pay rates applicable under the relevant award classifications and specified in Ergon Energy's Union Collective Agreement to 2010–11. Further, the AER notes Ergon

1934 Energex, response to AER.EGX.27.01, 5 October 2009, confidential.
1935 KPMG, Escalation rates for labour, materials and contractors, March 2008, p. 42.

Energy's labour cost escalation forecasts include provision for a 'network recovery payment' and 'EDSD allowance' to 2010–11.[1936]

The AER considers that compensating a DNSP for actual EBA wages increases in its expenditure forecasts, largely eliminates the incentive for a regulated DNSP to actively pursue efficient and competitive wage outcomes during EBA negotiations with its staff and representative unions. The AER acknowledges that salaries, and annual salary increases, are fundamental bargaining tools in EBA negotiations, however, it also considers that efficient and prudent businesses DNSPs would actively seek to negotiate favourable terms and conditions by leveraging other, non-financial negotiables, even in circumstances of perceived or apparent skilled labour shortages.

Compensating for actual EBA increases does not incentivise the DNSP to develop innovative bargaining strategies to attract and retain labour resources, as many businesses in competitive markets are forced to do in response to normal market pressures. Nor does the full compensation of historical EBA increases recognise that skilled labour shortages observed in recent years will invariably recede due to adjusting economic factors, such as resource mobility, in the medium to long term.

The AER will, however, observe the actual EBA rate increase incurred by Ergon Energy up until the beginning of the next regulatory control period, including an appropriate adjustment in 2010–11 to reflect the impact of the AER's indexing approach.

Application of the forecasts

The AER notes that Ergon Energy's opex labour cost escalators do not provide for specific labour escalation rates to apply to the different types of labour resources it is expected to require during the next regulatory control period. The AER's considerations on why this is not appropriate are set out above in its considerations on Energex.

In considering Energex's proposed internal labour escalators, the AER sought further information from Energex to establish the type of labour reflected in its internal and contract labour forecasts. In response, Ergon Energy advised that its resources may be categorised as Administrative, Technical Stream and Professional and Managerial.[1937] Ergon Energy submitted that the technical stream accounts for 73 per cent of its staff while the remaining 27 per cent are administrative, or professional and managerial.

The AER considers the general labour cost growth forecasts are an appropriate measure to escalate direct general labour costs incurred by Ergon Energy. The AER therefore considers it reasonable to apply general labour cost growth forecasts rather than EGW labour cost escalation to Ergon Energy's administration, professional and managerial stream employees. This group of employees account for approximately 27 per cent of Ergon Energy's workforce.[1938]

[1936] Ergon Energy, response to Q.AER.ERG.08.2, 3 September 2009, confidential.
[1937] Ergon Energy, response to Q.AER.ERG.15.05, 18 September 2009, confidential.
[1938] Ergon Energy, response to Q.AER.ERG.08.2, 3 September 2009, confidential.

The AER considers the EGW labour cost growth forecast as an appropriate measure to escalate EGW labour costs to employees broadly defined as industry specialists undertaking direct project work on-site.[1939] The AER therefore considers it reasonable to apply EGW labour cost escalation forecasts to labour costs incurred by Ergon Energy's technical stream employees, approximately 73 per cent of Ergon Energy's workforce.[1940]

The AER also considers that it is appropriate to apply forecasts based on the latest available data. Therefore, the AER will apply the Access Economics labour cost growth forecasts for Queensland, as produced in September 2009, in deriving labour cost escalators for Ergon Energy. The AER also considers it appropriate to further update these forecasts for the purposes of its final decision.

The AER's has calculated a weighted average contract labour escalator based on Ergon Energy's internal labour resources being estimated at 73 per cent specialist EGW, and 27 per cent general contract labour types, and derived using respective labour cost forecasts developed by Access Economics as discussed above. The AER's weighted average labour escalators for Ergon Energy's forecast internal labour costs are set out at table H.32.

Table H.32: AER weighted average internal labour escalators for Ergon Energy (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
AER real weighted average internal labour escalator	0.07	2.13	0.58	0.58	1.16	1.54	1.53

Source: AER analysis; Access Economics, Forecast growth in labour costs, 16 September 2009.

Regarding labour growth escalators used by SKM for developing capex asset class escalators, the AER considers its weighted average internal and contract labour escalators set out in this appendix should also be applied in the derivation of updated capex escalators, to ensure a consistent approach across Ergon Energy's expenditure forecasts for the 2008–09 to 2014–15 period.

Contract labour

The AER notes Ergon Energy escalated its contract rates by its internal labour escalator. The AER further notes Ergon Energy's union collective agreement requires contractor staff rates to be indexed against with Ergon Energy's staff rates.[1941] As discussed above, the AER does not consider it appropriate that forecast labour costs be established on the basis of a current EBA escalation rate.

In developing substitute contract labour escalation rates, the AER sought further information from Ergon Energy regarding the nature of the work performed by its

[1939] The AER has adopted this broad definition from SKM, *Electricity industry labour, commodity and asset price cost indices*, 6 October 2008.
[1940] Ergon Energy, response to Q.AER.ERG.15.5, 18 September 2009, confidential.
[1941] Ergon Energy, *Regulatory proposal*, July 2009, p. 339.

contractors. In response, Ergon Energy submitted that its contracted entities undertake a range of works, including design, construction, vegetation management, asset inspections and asset maintenance.[1942]

The AER considers the duties undertaken by Ergon Energy's contractors to be consistent with the broad definition of EGW workers. The AER further considers it appropriate to apply EGW wages to escalate such contract labour, given the bulk of these contracts are predominantly labour based with Ergon Energy supplying materials.[1943]

The AER will apply Access Economics' Queensland EGW labour cost growth forecasts, to Ergon Energy's contractor costs. The AER also considers it appropriate to further update these forecasts to reflect the most recent data, for the purposes of its final decision. The AER's contract labour escalators for Ergon Energy are set out in table H.33.

Table H.33: AER conclusion on real contract labour escalators for Ergon Energy (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Qld EGW	0.9	1.5	0.1	0.6	1.2	1.6	1.5

Source: AER analysis; Access Economics, *Forecast growth in labour costs*, 16 September 2009.

H.4.5 AER conclusion

For the reasons discussed and as a result of the AER's analysis of Energex's regulatory proposal, Access Economics' forecasts and other supporting information, the AER is not satisfied that Energex's labour cost escalation forecasts reasonably reflect the capex and opex criteria, including the capex and opex objectives. The AER has substituted the escalators set out in table H.34, and considers this is the minimum adjustment necessary for the internal labour cost growth forecasts to comply with the NER. In coming to this view, the AER has had regard to the capex and opex factors.

The AER's conclusions on Energex's forecast internal and contract labour cost escalators are set out in table H.34.

Table H.34: AER conclusion on Energex's real labour cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Internal labour	–0.03	2.51	0.69	0.57	1.20	1.56	1.54
Contract labour	0.77	1.38	0.14	0.58	1.17	1.54	1.53

[1942] Ergon Energy, request for information (Q.AER.ERG.08.4), 29 August 2009, confidential.
[1943] Ergon Energy, request for information (Q.AER.ERG.15.7), 18 September 2009, confidential.

For the reasons discussed and as a result of the AER's analysis of Ergon Energy's regulatory proposal, Access Economics' forecasts and other supporting information, the AER is not satisfied that Ergon Energy's labour cost escalation forecasts reasonably reflect the capex and opex criteria, including the capex and opex objectives. The AER has substituted the escalators set out in table H.35, and considers this is the minimum adjustment necessary for the internal labour cost growth forecasts to comply with the NER. In coming to this view, the AER has had regard to the capex and opex factors.

The AER's conclusions on Ergon Energy's forecast internal and contract labour cost escalators are set out in table H.35.

Table H.35: AER conclusion on Ergon Energy's real labour cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Contractors	0.9	1.5	0.1	0.6	1.2	1.6	1.5
Internal labour	0.07	2.13	0.58	0.58	1.16	1.54	1.53

I. Energex controllable operating expenditure

I.1 Introduction

This appendix is to be read in conjunction with chapter 8 of this draft decision. It sets out the AER's detailed considerations and conclusions on Energex's proposed controllable opex allowance for the next regulatory control period. The regulatory requirements and the general approach used by the AER to assess Energex's opex proposal are set out in chapter 8 of this draft decision.

The AER's review of controllable opex is undertaken separately to its review of input cost escalators (section 8.8.6 of this draft decision). The impact of revisions to input cost escalators is therefore not factored into the AER conclusions presented on controllable opex. The consolidated impact of all adjustments required by the AER (controllable opex, uncontrollable opex, capex/opex tradeoffs, and input cost escalation) is set out in the AER conclusions (section 8.9 of this draft decision).

I.2 Energex regulatory proposal

Table I.1 sets out Energex's current and forecast controllable opex by cost category and year.

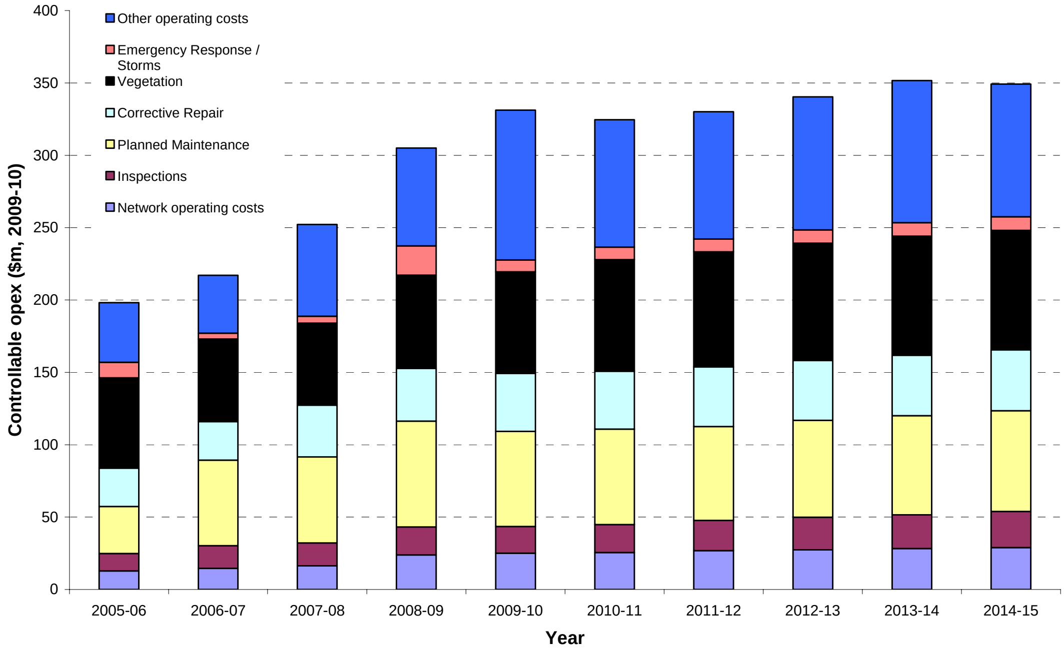
Table I.1: Energex actual and forecast controllable opex by category ($m, 2009–10)

Category	Actual			Estimated		Forecast				
	05–06	**06–07**	**07–08**	**08–09**	**09–10**	**10–11**	**11–12**	**12–13**	**13–14**	**14–15**
Network operations	12.8	14.4	16.3	23.7	25.0	25.5	26.8	27.4	28.3	28.9
Network maintenance	144.2	162.7	172.4	213.7	202.7	211.0	215.3	221.0	225.1	228.6
Other opex	58.5	64.4	60.8	75.5	105.2	118.6	118.7	122.9	127.0	118.0
Debt raising	0	0	0	0	0	7.2	8.1	9.0	9.9	10.7
Equity Raising	0	0	0	0	0	20.6	19.8	18.8	15.7	12.6
Self insurance	0	0	0	0	0	2.8	2.9	3.1	3.2	3.0
Total opex [a]	215.5	241.5	249.5	312.9	332.9	324.5	330.0	340.4	351.6	349.2

Source: Energex, *Regulatory Proposal*, July 2009, RIN opex pro forma 2.2.2, converted to real terms using ABS inflation data.
Note: Totals may not add due to rounding.
(a) Total controllable opex excludes debt raising costs, equity raising costs and self insurance.

Figure I.1 illustrates Energex's actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

Figure I.1: Energex actual and forecast controllable opex 2005–2015 ($m, 2009–10)



Source: Energex, *Regulatory Proposal*, July 2009 and RIN proforma 2.2.2.

Note: Other operating costs category consists of meter reading, customer services, DSM initiatives, levies and other support costs. Energex was unable to provide information for other support costs for the period prior to 2007–08. Thus figures in the table for 2005–06 and 2006–07 do not include other support costs.

The total controllable opex of $1696 million in the next regulatory control period is approximately 25 per cent higher in real terms than the estimated $1352 million for the current regulatory control period.[1944]

Energex stated that its forecast opex for the next regulatory control period has been prepared to:[1945]

- efficiently meet or manage the expected demand for standard control services
- maintain the quality, reliability and security of supply of those services
- maintain the reliability, safety and security of distribution systems
- comply with the applicable regulatory obligations and requirements associated with the provision of those services.

Energex stated the increased opex for the next regulatory control period contributed toward maintaining and improving the reliability performance of the network, particularly through effective vegetation management and improved maintenance programs. Forecast opex for these categories, when compared with the current regulatory control period, have increased by 29 per cent and 16 per cent,

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[1944] Energex stated that opex for the current regulatory control period complies with RIN requirements, as the data presented is consistent with the AER's approved cost allocation method.

[1945] Energex, *Regulatory proposal*, July 2009, p. 155.

respectively.[1946] Energex forecast significant step changes in all of its opex categories except meter reading.[1947]

Energex further stated the following reasons for changes in controllable opex:[1948]

- new programs to progress towards compliance with the Electricity Distribution and Service Delivery review (EDSD Review) and legislative compliance
- maintenance and management of an expanding asset base
- increased inspection and maintenance programs resulting from the introduction of a condition based risk management (CBRM) approach to asset renewal and refurbishment
- forecast customer growth
- real cost escalation.

I.3 Issues and AER considerations

I.3.1 Opex forecasting methodology

Energex regulatory proposal

Energex utilised a two step process to determine its forecast opex for the next regulatory control period. Energex constructed its opex forecasts using a bottom up approach, followed by a top down review which assessed the resulting forecasts against industry accepted efficiency benchmarks. Energex's approach incorporated Wilson Cook's methodology in its assessment of efficient opex forecasts.[1949] This approach found a composite variable of customer numbers and line length compared with opex provided the best correlation with total opex.[1950]

Energex stated it also participates in national and international industry benchmarking studies to ensure its expenditure is comparable with industry efficient benchmarks.[1951]

Energex advised that the process it uses to develop its opex forecasts is based on its Network Strategy.[1952] Additionally it indicated that its opex forecasts are underpinned by key internal documents, namely its *substation asset maintenance policy* (SAMP) and *mains asset maintenance policy* (MAMP). Energex stated that these documents

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1946 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, converted to real terms using ABS inflation data.
1947 Energex, *Regulatory proposal*, July 2009, pp. 182–188 and RIN proforma 2.2.4.
1948 Energex, *Regulatory proposal*, July 2009, p. 183.
1949 Wilson Cook & Co, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 1, October 2008, pp. 18–27.
1950 Energex, *Regulatory proposal*, July 2009, p. 160.
1951 Energex, *Regulatory proposal*, July 2009, p. 160.
1952 Energex, *Regulatory proposal*, July 2009, p. 162. For a summary of Energex's Network Strategy see Energex, *Regulatory proposal*, July 2009, pp. 63–77.

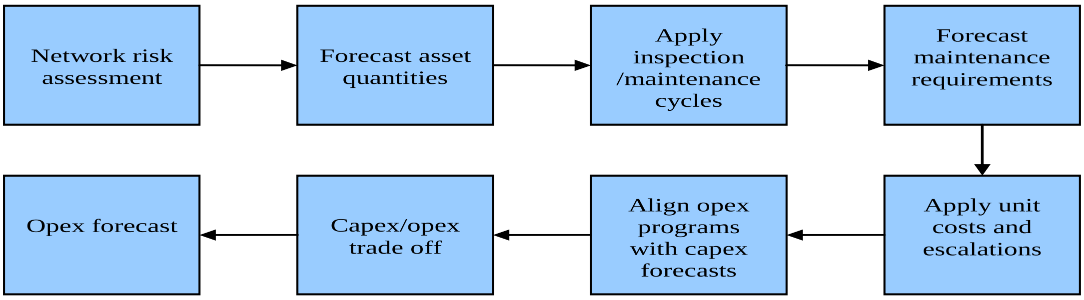
provide Energex with a basis on which to build bottom up opex forecasts, while ensuring its compliance with relevant legislation.[1953]

To determine its final opex forecasts, Energex used a two part process. The first stage of this process features the following steps:[1954]

- prepare a network risk assessment to identify assets and services that require expenditure
- analyse the asset base over the five year period to forecast asset quantities
- apply inspection and maintenance cycles in respect to each asset class
- calculate an estimate of maintenance requirements based on historical equipment failure rates
- calculate and estimate unit costs for materials, labour and contractors and incorporate escalations as required for the five year period
- align capital and operational programs
- identify opportunities for capex/opex trade offs
- calculate forecast opex for the next regulatory control period.

This process is illustrated in figure I.2.

Figure I. 2: Energex's opex forecasting methodology



Source: Energex, *Regulatory Proposal*, July 2009, p. 161.

The second stage of Energex's opex forecasting process involves an assessment of the efficiency of the forecasts using the following additional steps:[1955]

- compare expenditure program against industry benchmarks

[1953] Energex, *Regulatory proposal*, July 2009, p. 162.
[1954] Energex, *Regulatory proposal*, July 2009, pp. 161–162.
[1955] Energex, *Regulatory proposal*, July 2009, p. 162.

- determine the efficiency of the opex program
- investigate and justify any variance
- if the program fails to meet the objectives of the NER at clause 6.5.6(a) or does not satisfy the efficiency test or has unexplained variance, the program is resubmitted for network risk assessment and a re-run of part one of the process
- if the forecast opex is found to be efficient with any variance justified, the program including other operating costs is submitted to the Network Technical Committee of the Energex Board for endorsement and ultimately to the Energex Board for approval as part of the Network Management Plan.

Capex / opex trade off

Energex stated it considered capex/opex trade–offs through:[1956]

- Design and maintenance standards – Energex stated that its network strategy is designed to minimise whole of life costs of each asset. Energex stated that high maintenance items are removed from the network by eliminating that inclusion at the design stage or using low maintenance alternatives. Energex also introduces new, technologically superior equipment to achieve enhanced network outcomes.
- Renew, replace or maintain assets – the decision to replace or maintain an asset is supported by the comprehensive CBRM methodology that Energex has implemented. Energex cites that CBRM has been applied to low voltage (LV) powerlines where detailed analysis shows that rebuilding the overhead lines using a bundled conductor provides better reliability and quality of supply while reducing costs associated with tree clearing and other maintenance.
- Equipment specification and purchasing – when purchasing assets, Energex stated that it seeks to minimise whole of life costs. This assessment is incorporated into the procurement process.

Consultant review

PB's review of Energex's opex forecasting methodology involved an assessment of:[1957]

- the methodology and accuracy of the asset quantity forecasts
- the cost efficiency of the unit costs
- defect ratios
- the methodology used to project historical expenditure trends.

[1956] Energex, *Regulatory proposal,* July 2009, pp. 175–176.
[1957] PB, *Report – Energex*, October 2009, p. 92.

PB found that the forecasting methodology used by Energex to determine its opex forecasts was likely to result in accurate and reasonable forecasts. In particular, PB made the following findings:[1958]

- most expenditure categories have been forecast based on historical quantities, adjusted to reflect the proposed capex program

- average unit costs were used based on historical actual costs and reviewed to ensure total costs aligned with the number of units maintained. In addition, PB was satisfied that the historical costs aligned with the reported number of units maintained.

- where historical trends have been used in forecasting, these have been observed over sufficient periods to counter the impacts of annual variability (for example, changing weather patterns and the impact on emergency response expenditures).[1959]

PB also examined the underlying compliance documentation, assumptions and calculations upon which Energex's opex forecasts were based. PB found that Energex had used its normal business processes to develop its opex forecasts for the next regulatory control period. From its review of the SAMP and MAMP, PB concluded that the specific inspection and maintenance activities relating to specific assets are detailed and would enable accurate work volumes to be forecast for the next regulatory control period.[1960]

PB also reviewed the opex forecasts with reference to the detailed asset quantities used in the forecast capital works program. This review confirmed that the works programs are interrelated, and asset quantities included in the opex programs reflect the related capex programs.[1961] PB stated that Energex's approach of incorporating the impact of the proposed asset replacement programs at the Network Asset Management Program (NAMP) line item level was an accurate methodology. PB concluded that the forecast asset quantities incorporated into Energex's opex modelling are sufficiently accurate for the purpose of forecasting expenditures.[1962]

AER considerations

The AER reviewed Energex's NAMP in conjunction with the SAMP and MAMP in its evaluation of Energex's opex forecasting methodology.[1963] The AER considers the methodology of forecasting asset quantities at the individual program level to be a reliable method of building bottom up opex forecasts. The AER also notes that there is an equivalent document for the capex program.[1964] By identifying the interlinkages between the two management procedures for capex and opex, it is apparent that Energex has taken account of the forecast capital works program in developing its

1958 PB, *Report – Energex*, October 2009, p. 90 and p. 99.
1959 PB, *Report – Energex*, October 2009, p. 99.
1960 PB, *Report – Energex*, October 2009, pp. 94–95.
1961 PB, *Report – Energex*, October 2009, p. 94.
1962 PB, *Report – Energex*, October 2009, pp. 94–95.
1963 Energex, *Distribution and Transmission Operating Program*, 2006–2016, July 2009, confidential.
1964 Energex, *Distribution Capital, Recoverable and Alternative Control Services*, 2006–2016, July 2009, confidential.

opex forecasts. The AER considers that this directly satisfies the AER's requirement under the NER to consider the capex/opex trade off in its assessment of Energex's proposal.[1965]

The AER notes that this approach differs from the traditional top down approach used by many DNSPs, where forecasts are derived by applying escalation assumptions and step changes to an efficient base year opex. However, the AER considers that Energex's detailed bottom up forecasting methodology is likely to result in reasonable and considered opex forecasts which reasonably reflect Energex's efficient forecast expenditure requirements.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, submissions, PB's report and supporting information, the AER considers that the forecasting methodology employed by Energex is sufficiently detailed and is likely to result in generally efficient opex forecasts.

The AER does not, however, consider that Energex's real input cost escalators that it has applied in its expenditure modelling processes are reasonable. The AER's considerations on Energex's real cost escalators are discussed in detail in appendix H.

I.3.2 Efficient base year

Regulatory proposal

Energex did not employ a top down escalation model applied to an efficient base year to develop its opex forecasts. Rather, it employed a bottom up approach to derive the opex forecast, with 2007–08 data being used to illustrate the efficiency of its current and forecast opex program.[1966]

Energex stated the 2007–08 opex represents expenditure which forms a basis to enable Energex to further increase its capability and progress toward EDSD Review compliance.[1967]

Submissions

Origin stated that the current period should only be a precursor to further spending if Energex is making reasonable progress towards its goals. Origin wanted Energex to provide more information on the trajectory that Energex envisages for reaching these goals.[1968] Origin also questioned the usefulness of some of Energex's benchmarking. It stated in light of the proposed opex increase, the benchmarking Energex relies on needs to be more transparent than that contained in section 12.10 of Energex's regulatory proposal.[1969]

[1965] NER, clause 6.5.6(e)(7).
[1966] Energex, *Regulatory proposal*, July 2009, p. 181.
[1967] Energex, *Regulatory proposal*, July 2009, p. 181.
[1968] Origin, *Queensland DNSPs*, August 2009, p. 5.
[1969] Origin, *Queensland DNSPs*, August 2009, p. 7.

Consultant review

PB did not consider a review of Energex's 2007–08 efficient base year was necessary as Energex did not employ a traditional base year methodology to escalate its opex forecasts. Rather, PB focussed on the assumptions underlying Energex's forecasting methodology.[1970] In this respect, where Energex used historical data to inform the opex forecasts, PB noted that Energex used periods extending back over the current regulatory control period.[1971] PB stated that in its view this approach assisted in smoothing the variations that can occur within some opex categories.[1972]

AER considerations

Energex has applied a detailed bottom up approach to derive its opex forecast, rather than a top down or base year approach. Energex's references to 2007–08 data have only been used to illustrate the efficiency of its historical and forecast opex program by allowing Energex to identify 'significant variations'.

The AER notes that the Regulatory Information Notice (RIN) stipulates that any 'significant variations from' the base year must be explained in the regulatory proposal.[1973] In the RIN templates provided by Energex, comparisons are based on 2007–08 data. The AER considers that using 2007–08 data for this purpose is appropriate as the data was the latest audited regulatory account information at the time Energex's regulatory proposal was prepared.

Benchmarking

The NER sets out the factors that the AER must consider when assessing whether or not it is satisfied by a DNSP's forecast opex.[1974] In determining whether or not the proposed forecast opex meets the opex criteria, AER must have regard to the opex factors, which include:[1975]

> benchmark opex that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.

Energex used an opex benchmarking model as its primary tool for judging opex efficiency. Its opex benchmarking model used a composite variable, comprised of customer numbers and line length, compared with overall opex, to judge efficiency. By comparing its position against the industry benchmark line Energex determined that its opex in 2007–08 was at an efficient level.[1976]

Energex also engaged SAHA International Limited (SAHA) to conduct a more detailed examination of its opex efficiency. SAHA concluded that Energex's opex was efficient.[1977] SAHA also looked at the two component categories of asset maintenance, underground and overhead maintenance, due to the large influence that asset maintenance has on opex. SAHA found that Energex had the lowest

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1970 PB, *Report – Energex*, October 2009, p. 90.
1971 PB, *Report – Energex*, October 2009, p. 90.
1972 PB, *Report – Energex*, October 2009, p. 90.
1973 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.4.
1974 NER, clause 6.5.6(e)(1)–(10).
1975 NER, clause 6.5.6(e)(4).
1976 Energex, *Regulatory proposal*, July 2009, pp. 178–179.
1977 SAHA, *Energex Electricity Distribution Business Operational Expenditure Review*, p. 19.

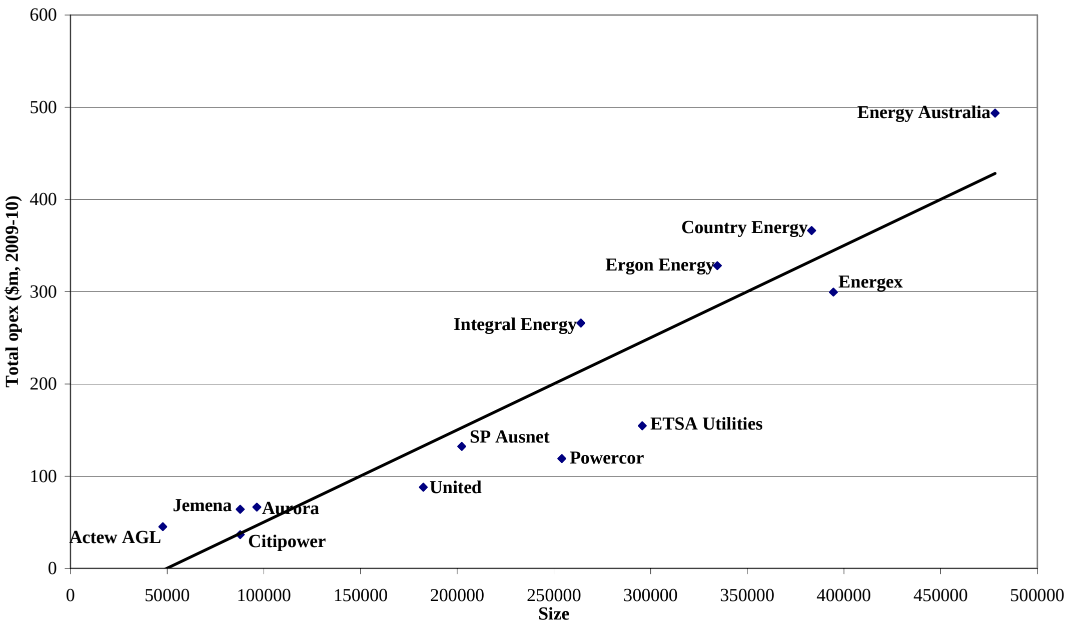
maintenance cost per kilometre of all participating DNSPs. In regard to overhead asset maintenance, SAHA noted that Energex's unit costs were a result of rectification of deficiencies in the network, including cross arm replacement, which increased Energex's unit costs to a position equivalent to comparable DNSPs.[1978]

The AER also undertook benchmarking, including ratio analysis and regression analysis of measures of Energex's 2007–08 (baseline) opex against other Australian DNSPs.

The AER provided its ratio analysis to PB, who considered the results in conjunction with the benchmarking undertaken by Energex and concluded that Energex's opex forecasts are relatively efficient from a top down, inter–business comparative perspective.[1979]

The AER's regression analysis also compared 2007–08 data of DNSPs in Australia. Figure I.3 shows the results of the AER's regression analysis for DNSPs in Australia.

Figure I.3: Comparative analysis of opex versus size for Australian DNSPs ($m, 2009–10)



Source: AER, internal analysis.

Consistent with the ratio analysis undertaken by the AER, and the benchmarking conducted by Energex and SAHA, Energex sits below the regression line, indicating that it has relatively low opex in 2007–08 in comparison to other Australian DNSPs in the sample. This analysis takes into account factors such as the relative size of the DNSPs' networks, and, to the extent possible, data gathered on a like for like basis.

[1978] SAHA, *Energex Electricity Distribution Business Operational Expenditure Review*, pp. 36–38.
[1979] PB, *Report – Energex*, October 2009, pp. 117–119.

The AER also notes the comments of the EUAA, noting the AER's obligation to undertake benchmarking when reviewing opex forecasts.[1980] In particular, the EUAA seemed to be requesting that the opex forecasts be adjusted largely on the basis of benchmarking studies.

However, the limitations of the benchmarking work, in terms of the size of the data set, discrepancies in opex definitions and differing regulatory arrangements for comparator DNSPs limits the use of the benchmarking results as a tool for justifying amendments to opex forecasts. The AER also considers the general limitations of benchmark analysis are recognised by the NER, as benchmarking is only one of ten factors that the AER must have regard to when assessing a DNSP's proposed opex forecast.[1981]

The AER therefore considers that while benchmarking is a useful analytical tool, its use should be limited to a top down testing of more detailed bottom up assessment, informed by due consideration of each of the factors specified in clause 6.5.6(e) of the NER.

As required under clause 6.5.6(e)(4) of the NER, the AER has had regard to benchmarking information as provided by Energex, and its own internal analysis. The AER notes the outcomes of these benchmarking studies, and observes that Energex's opex appears relatively low in 2007–08 compared to the sample. The AER considers there are reasonable explanations for this outcome, and has considered these factors in its assessment of the prudence and efficiency of Energex's base year opex (where relevant), and forecast opex for the next regulatory control period.

AER conclusion

The AER considers that using 2007–08 data as the base year for comparison against Energex's forecast opex is appropriate as the data was the latest audited regulatory account information at the time Energex's regulatory proposal was prepared.

As required under clause 6.5.6(e)(4) of the NER, the AER has had regard to benchmarking information as provided by Energex, and its own analysis. The AER notes the outcomes of the benchmarking studies for Energex, and notes that Energex's opex appears relatively efficient in 2007–08 compared to the sample.

I.3.3 Maintenance strategy and implementation

Regulatory proposal

Energex commissioned SAHA to review the efficiency of its opex. In relation to Energex's implementation of its asset maintenance strategies, SAHA concluded that:[1982]

> Those areas where Energex has focused expenditure over the period…the results in terms of favourable failure rates and increased reliability demonstrate a high level of success of those deliberate programs.

[1980] EUAA, *Submission to the AER*, 28 August 2009, p. 13–17.
[1981] NER, clause 6.5.6.
[1982] SAHA, *Energex Electricity Distribution Business Operational Expenditure Review*, June 2009, p. 19.

Energex also compared its practice with those of networks in the UK which it considered similar.[1983] EA Technology assisted Energex to undertake a comparative study.[1984] Broadly, EA Technology found that there was scope for Energex to improve in the maintenance policy function and within asset maintenance in general.[1985] However, EA Technology concluded that, while some of its high-level strategic recommendations may take time to implement, a number of its recommendations, particularly relating to maintenance practices and intervals would be relatively quick and straightforward to implement.[1986]

EA Technology separately reviewed Energex's SAMP and MAMP. While EA Technology recommended the development of a higher level, overarching asset management strategy, EA Technology found that most asset classes have adequate inspection and maintenance intervals and did not identify any major omissions.[1987]

Consultant review

PB reviewed the key documentation and policies that underpin Energex's asset management practices. Overall, PB considered that Energex possessed well established asset management policies and prudent risk management principles that form the basis of its current asset management practices. In particular, PB considered that the use of the detailed CBRM model to inform replacement and refurbishment capex and maintenance is a leading edge industry practice amongst Australian DNSPs.[1988]

PB found that, where possible, Energex based its maintenance decisions on asset condition with the exception of low cost, run to failure assets. PB considered that the approach implemented by Energex in respect of maintaining its network is transparent, comprehensive and in line with good electricity industry practice.[1989]

Based on correspondence with Energex staff, its review of the SAMP and MAMP, and the review of EA Technology's independent maintenance policy review, PB concluded that Energex's opex forecasts are based on prudent asset management principles, processes and procedures.[1990]

AER considerations

The AER has reviewed the supporting documentation that underpins Energex's asset maintenance strategy, including the SAMP, MAMP and NAMP. Based on this analysis, and the advice provided to the AER by PB, the AER considers that these strategies appear comprehensive, well documented and transparent and are likely to result in prudent and efficient maintenance practices consistent with good electricity industry practice.

[1983] Energex, *Regulatory proposal*, July 2009, p. 160.
[1984] EA Technology Consulting, *Maintenance Policy Review for Energex*, January 2008.
[1985] EA Technology Consulting, *Maintenance Policy Review for Energex*, p. iv.
[1986] EA Technology Consulting, *Maintenance Policy Review for Energex*, p. iv.
[1987] EA Technology Consulting, *Full Application of Condition Based Risk Management with Energex*, July 2008, pp. 76–80.
[1988] PB, *Report – Energex*, October 2009, p. 88.
[1989] PB, *Report – Energex*, October 2009, p. 89.
[1990] PB, *Report – Energex*, October 2009, p. 89.

The AER considers that Energex's CBRM modelling approach is a sound asset management framework and is likely to produce efficiencies in the long term. The AER notes comments made by EA Technologies that building 'health indices' for each asset class, and the derivation of probabilities of failure for each asset class is a prudent and efficient way of managing the risks of failure within the network.[1991] The AER considers that Energex has incorporated the efficient costs and future benefits of implementing its CBRM framework into its opex forecasts. These cost efficiencies and future benefits include Energex obtaining a better understanding of asset conditions and asset repair schedules, and thus being able to address assets that require special attention. The AER considers that these efficiencies and benefits are reflected in the real decreases (that is, before real input cost escalations are applied) in planned and corrective maintenance opex over the next regulatory control period.

The AER considers that Energex is well advanced in its implementation of condition and risk based modelling and the continued development of these systems reflects a prudent approach to asset management in Energex's circumstances.

AER conclusion

Having considered Energex's opex planning and governance framework, other documents and advice from PB, the AER is satisfied that Energex's policies and procedures for opex planning and governance generally demonstrate that their application is likely to lead to prudent and efficient expenditure decisions.

I.3.4 Network operating costs

Regulatory proposal

Energex advised that its forecast opex for network operating costs included activities required to configure, monitor and operate the network.[1992] This includes activities such as:[1993]

- high voltage access and isolation switching
- updating and maintaining operating panel drawings
- preparing contingency plans
- evaluating network incidents
- managing emergency response
- investigations into reliability of supply, power quality and load control.

Table I.2 illustrates Energex's forecast network operating costs for the next regulatory control period.

[1991] EA Technology Consulting, *Full Application of CBRM,* July 2008, p. 3.
[1992] Energex, *Regulatory proposal,* July 2009, p. 164.
[1993] Energex, *Regulatory proposal,* July 2009, p. 164.

Table I.2: Energex forecast network operating costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Network operating	25.5	26.8	27.4	28.3	28.9	137.0

Source: Energex, RIN proforma 2.2.2.
Note: Totals may not add due to rounding.

Total network operating costs in the next regulatory control period are forecast to increase by 48 per cent compared to total network operating costs in the current regulatory control period.[1994] Network operating costs account for approximately 7 per cent of Energex's total forecast opex.[1995]

Energex stated that a significant reason for the increase in network operating costs was the rise in network control costs, resulting from a highly loaded network that requires additional maintenance, extensive switching and increased after hours access. Energex states that this results from a more stringent application of the *Electrical Safety Act (2002)*, which places restrictions on working on live equipment. Energex also pointed to an increased reliance on mobile generators to maintain reliability compliance during peak load times, plus a new program to balance the load on low voltage mains.[1996]

Consultant review

PB's top down analysis of network operating costs involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing them to opex in the current regulatory control period. PB stated that this indicated a business as usual expenditure pattern from 2008–09 onwards. PB noted that expenditures were forecast using historical quantities and average unit costs for the 2008–09 financial year.[1997]

Given the business as usual trend, and the detailed approach Energex has used to forecast opex for the next regulatory control period, PB recommended that the proposed opex for network operations should be accepted with no changes.[1998]

AER considerations

The AER notes PB's examination of Energex's forecasting methodology, and notes PB was satisfied with the derivation of the proposed network operating expenses due to the detailed nature of the bottom up forecasts.

The AER notes that spending associated with switching, resulting from the more stringent application of the *Electrical Safety Act (2002)*, shows a decreasing trend from 2006–07 to 2008–09 then increases from 2009–10 onwards.[1999] The AER also

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1994 The percentage change figure represents the percentage change of the average network opex during the next regulatory control period compared to the 2007– 08 base year, in real terms.

1995 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2.

1996 Energex, *Regulatory proposal*, July 2009, p. 185.

1997 PB, *Report – Energex*, October 2009, p. 100.

1998 PB, *Report – Energex*, October 2009, pp. 100–101.

1999 Energex, *Distribution and Transmission Operating Program*, 2006–2016, July 2009, line item NO04, pp. 233–234.

notes the network operations opex proposed by Energex to comply with the *Electrical Safety Act* has not increased due to changes in the Act, but reflect a more stringent interpretation and thus higher costs associated with complying with the Act.

The AER considers that there are clear benefits to the employees of Energex, and the wider public from the strict adherence to the provisions of the *Electrical Safety Act* and on that basis the AER considers such expenditure to be prudent. The AER also accepts this more rigorous adherence to the *Electrical Safety ACT 2002* as it complies with the opex objectives, particularly clauses 6.5.6.(a)(2) and 6.5.6.(a)(4) of the NER.

The AER recognises that network operating costs are likely to increase as the network grows. The AER examined the network operating costs forecasts before real cost escalations were applied, and considers that the growth in network operating costs over the next regulatory control period is primarily driven by the substantial capex program proposed by Energex. However, the AER considers that Energex has taken account of growth capex in a conservative fashion. The AER considers that Energex's methodology is acceptable.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed network operating costs reasonably reflect the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.5 Network maintenance

Regulatory proposal

Table I.3 shows Energex's forecast network maintenance opex for the next regulatory control period.

Table I.3: Energex forecast network maintenance opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Inspection	19.2	20.8	22.5	23.2	25.0	110.8
Planned maintenance	66.0	65.0	66.9	68.5	69.6	336.0
Corrective repair	40.0	41.1	41.4	41.9	42.1	206.4
Vegetation	77.2	79.5	81.1	82.2	82.5	402.6
Emergency response/storms	8.6	8.9	9.1	9.3	9.4	45.2
Total network maintenance	211.0	215.3	221.0	225.1	228.6	1101.0

Source: Energex, *Regulatory Proposal*, July 2009, RIN opex proforma 2.2.2.
Note: Totals may not add due to rounding.

Energex's total forecast network maintenance expenditure is $1101 million over the next regulatory control period. Energex has forecast an increase in total network maintenance opex of 23 per cent compared to the current regulatory control period.

Network maintenance opex accounts for approximately 60 per cent of Energex's total opex in the next regulatory control period. Energex stated the average yearly expenditure figure of $220 million over the next regulatory control period is $48 million, or 28 per cent greater than the equivalent 2007–08 network maintenance opex, in real terms.[2000] [2001]

Energex stated that the primary drivers behind the increase in maintenance expenditure are:

- the purchase of a new risk management system, CBRM, in order to better understand the maintenance requirements of the network. Energex stated that this will result in more frequent inspection schedules and an anticipated increase in planned maintenance in order to achieve the overall objective of improved asset management and reliability[2002]

- increased vegetation management expenditure due to revised vegetation management initiatives. Energex has reduced its trimming cycle from 30 months to 15 months for low voltage urban lines, in response to 'more typical rainfall patterns'[2003]

- emergency response/storms costs are expected to increase, as the 2007–08 year was an exceptionally mild year. By comparison, the 2008–09 storm season was far more severe, resulting in an actual cost (to date) of $20 million.[2004]

I.3.5.1 Inspection

Regulatory proposal

Energex stated its inspection program detects potential defects requiring remedial response as part of the planned maintenance program. Inspection cycles are derived from the SAMP and MAMP. Inspection costs for each category of plant and equipment are developed using forecast quantities based on unit costs and inspection cycles.[2005]

Energex forecast total inspection expenditure of $111 million for the next regulatory control period, which represents a real increase of 36 per cent compared to the current

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[2000] Energex, *Regulatory proposal*, July 2009, RIN opex proforma 2.2.2, confidential.
[2001] The percentage change figure represents the percentage change of the average network maintenance opex during the next regulatory control period when compared to the 2007– 08 base year, in real terms.
[2002] Energex, *Regulatory proposal*, July 2009, p. 186.
[2003] Energex, *Regulatory proposal*, July 2009, pp. 183–184. The AER notes that for the 2008 calendar year, Brisbane received 1241mm of rain, compared to an average of 1146mm. Bureau of Meteorology, *Queensland and Brisbane Monthly Climate Summary Archive*, <http://www.bom.gov.au/climate/current/month/qld/archive/>.
[2004] Energex, *Regulatory proposal*, July 2009, p. 187.
[2005] Energex, *Regulatory proposal*, July 2009, p. 165.

regulatory control period.[2006] Energex stated that the primary drivers of the cost increases were the introduction of CBRM and network growth.[2007]

Consultant review

PB conducted a top down review by backing out the real cost escalations built into the forecasts and comparing them to the current period expenditures. PB also reviewed the bottom up process used to determine the forecasts for this activity.[2008]

PB advised that its top down review indicated a business as usual expenditure pattern from 2008–09 onwards. Its bottom up review concentrated on the inspection quantities included in the opex modelling.

PB noted that Energex forecast a 16 per cent real increase (that is, before real input cost escalations were applied) in inspection costs. This increase arises from the proposed capital works programs and a number of additional proposed inspection programs. Two of these programs relate to compliance issues, which PB considered mandatory.[2009] The other inspection programs have been included because the introduction of the CBRM program identified assets where additional inspections would identify assets prior to defects resulting in failure, and assets that may pose risks to the public.[2010] PB considered the forecasts reasonable, and recommended that the forecast inspection expenditures should be accepted with no change.[2011]

AER considerations

The AER accepts that the introduction of CBRM programs will result in a higher level of inspections soon after the implementation of the methodology. Additionally, the AER would expect that the number of inspections would increase as the size of the network asset base increases, in accordance with the proposed capital works program. From analysis of the NAMP documents for both capex and opex, it is apparent that the increase in inspection expenditure is largely driven by these two factors.

The AER considers that expenditure in relation to compliance issues is generally prudent. The AER notes that the opex proposed for testing substation earth mats on a five year cyclic program has been forecast on the basis of complying with internal compliance procedures and this procedure is documented in Energex's SAMP.[2012] The AER also notes that PB considered these compliance programs mandatory.[2013]

The AER considers that the forecasting methodology employed by Energex is likely to produce a reasonable estimate, and as such the AER considers that the opex forecast for inspections is generally prudent.

2006 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2.
2007 Energex, *Regulatory proposal*, July 2009, pp. 186–187.
2008 PB, *Report – Energex*, October 2009, p. 101.
2009 PB, *Report – Energex*, October 2009, pp. 101–102. The two compliance programs are testing substation earth mats on a five year program and a renewed focus on testing protection equipment to achieve compliance.
2010 PB, *Report – Energex*, October 2009, p. 102.
2011 PB, *Report – Energex*, October 2009, p. 102.
2012 Energex, *Substation Asset Maintenance Policy*, 2009, p. 8.
2013 PB, *Report – Energex*, October 2009, p. 102.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed inspections opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.5.2 Planned maintenance

Regulatory proposal

Energex developed a planned maintenance schedule based on its CBRM methodology. Its approach seeks to identify defects prior to equipment failure and expenditure for this category is a direct outcome of the inspections program. Energex stated its planned maintenance forecasts for each category of plant and equipment are developed as follows:[2014]

- forecast quantities based on historical failure rates per units inspected
- apply unit costs
- consider capex/opex trade offs.

Energex forecasts total planned maintenance opex of $336 million over the next regulatory control period.

Total planned maintenance expenditure is forecast to increase by 36 per cent in real terms compared to the current regulatory control period.[2015] Energex stated that the primary drivers of the growth in this category were the introduction of CBRM and network growth.[2016]

Consultant review

PB's top down analysis of this activity involved backing out the real cost escalation built into the forecasts and comparing them to the current regulatory control period expenditures. PB noted Energex has incorporated CBRM into its opex programs since 2007. PB compared the average yearly spend on planned maintenance since 2007 with the average for the next regulatory control period, and advised that this indicated a decrease of 6 per cent in real terms between each period (that is, before real input cost escalations were applied). PB also indicated a reducing trend in expenditure over the next regulatory control period. PB confirmed that Energex's planned maintenance forecasts were constructed from a combination of forecast maintenance based on the SAMP and MAMP, historical defect ratios associated with the quantity of forecast inspections and average unit costs for the 2008–09 financial year.[2017]

[2014] Energex, *Regulatory proposal*, July 2009, p. 166.
[2015] Energex, *Regulatory proposal*, July 2009 and RIN proforma 2.2.2.
[2016] Energex, *Regulatory proposal*, July 2009, pp. 186–187.
[2017] PB, *Report – Energex*, October 2009, p. 103.

PB recommended that, given the detailed forecasting methodology and overall decrease in expenditure for this category, the opex forecasts for planned maintenance should be accepted with no change.[2018]

AER considerations

The AER notes Energex's process of utilising the SAMP and MAMP in conjunction with a forecast quantity methodology in order to determine a bottom up forecast of planned maintenance opex. The AER considers that this process produces an accurate reflection of the capital works program and the effects this has on the maintenance schedules of assets. As a result of this process, the AER considers that Energex will also be able to incorporate the cost effects of CBRM. For example, the implementation of CBRM, in the short term, may lead to greater inspections, which will generally have flow on effects to planned maintenance expenditure.

The AER is cognisant of PB's analysis which shows that there is a real reduction in planned maintenance costs over the next regulatory control period. This is after accommodating for growth in the asset base. After analysing the NAMP line items[2019] for both the proposed capex and opex programs, the AER considers that Energex has appropriately incorporated the capital works program in its planned maintenance forecasts, even though there is a real net decrease in expenditure for this cost category over the next regulatory control period. This decrease is driven largely by expected efficiencies arising from Energex's ongoing application of its condition and risk based asset management approach.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed planned maintenance expenditure reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.5.3 Corrective repair

Regulatory proposal

Corrective repairs are works undertaken after a failure of an asset to either return the network to a state in which it can perform required functions or render the installation safe to allow planned maintenance or replacement.[2020] Energex forecast corrective repair opex on the basis of historical costs.[2021]

Total corrective repair expenditure is forecast to be $206 million in the next regulatory control period, which represents a real increase of 25 per cent compared to the current regulatory control period.[2022] Energex stated that the primary driver of

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2018 PB, *Report – Energex*, October 2009, pp. 103–104.

2019 A NAMP line item is a subcategory of larger opex cost categories which illustrates the total quantities that have been, and will be, necessary to complete a particular opex task for the current and next regulatory control periods.

2020 Energex, *Regulatory proposal*, July 2009, p. 166.

2021 Energex, *Regulatory proposal*, July 2009, p. 166.

2022 Energex, *Regulatory proposal*, July 2009, p, 187.

growth in this category was a refinement of internal policy whereby costs that were previously allocated to emergency response/storms are now included in corrective repair.[2023] Energex advised that this was as a result of internal efficiencies being achieved, rather than a change in the way costs are booked to these cost categories.[2024]

Energex advised that there was considerable uncertainty associated with budgeted figures for this category and there may be significant overspends or underspends within this category.[2025] Energex advised that the forecasts for each individual NAMP line item were based on historical costs.[2026]

Consultant review

PB's top down analysis of this activity involved backing out the real cost escalation built into the forecasts and comparing them to the current period expenditures. PB stated this indicates a business as usual expenditure pattern from 2008–09 onwards. PB advised that the opex forecasts for this category were forecast using historical expenditures and that Energex advised a small reduction of $1.7 million in real terms is expected in the next regulatory control period. PB noted this has been factored into the forecasts to account for the further deployment of CBRM in the asset replacement strategy and means that more assets with a higher risk of failure are scheduled for replacement over the same period.[2027]

PB recommended that the opex forecasts for corrective repair be accepted with no change.[2028]

AER considerations

The AER has considered the analysis undertaken by PB in relation to corrective repair opex. The AER notes the $1.7 million real reduction in corrective repair opex reflects the implementation of CBRM.[2029] The AER considers that Energex has appropriately reflected the efficiencies from the implementation of CBRM and notes that the reduction of $1.7 million occurs despite a significant forecast growth in network assets.

While the overall expenditure pattern displays a business as usual pattern from 2008–09 onwards, the AER notes that several line items in Energex's NAMP document have extremely high forecasts when compared to the actual expenditures for these items in the preceding years. In particular, the AER notes actual expenditure in 2008–09 is far lower than the budgeted amount and is in line with actual expenditures in 2006–07 and 2007–08.[2030]

[2023] Energex, *Regulatory proposal*, July 2009, pp. 186–187.
[2024] Energex, email response, AER.EGX.30, 27 October 2009.
[2025] Energex, email response, PB.EGX.VP.40, 24 July 2009.
[2026] Energex, email response, PB.EGX.VP.35–39.
[2027] PB, *Report – Energex*, October 2009, p. 104.
[2028] PB, *Report – Energex*, October 2009, p. 105.
[2029] PB, *Report – Energex*, October 2009, p. 104.
[2030] Energex, email response, PB.EGX.VP.36–39, 24 July 2009.

However, the AER notes the uncertainty that surrounds this cost category due to seasonal and annual storm season variability and accepts that forecasts must be made using historical averages. This will mean that, due to the high degree of variability between years, there may be significant over and underspends within this cost category. The AER notes that mild storm seasons have contributed to underspending when actuals are compared with budgeted forecasts. The AER considers the methodology that Energex employs, using historical trends to forecast future corrective repair opex, is a prudent and efficient methodology of opex forecasting for this category.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed corrective repair expenditure reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.5.4 Vegetation management

Regulatory proposal

Vegetation management is a preventative measure that forms a key part of Energex's reliability strategy. The guidelines for Energex's vegetation management are outlined in its MAMP. Energex noted the EDSD Review identified vegetation management as an area where underspending had resulted in greater outages than would otherwise be the case. Energex stated that as vegetation management work is outsourced, vegetation management forecasts are based on the contracts used for completing this work.[2031]

Energex forecast total vegetation management expenditure of $403 million for the next regulatory control period, which represents a real increase of 30 per cent compared to the current regulatory control period.[2032] Energex stated that the primary driver of growth in this category was the decision to reduce the trimming cycles on low voltage urban lines from 30 to 15 months, brought about by a return to 'more typical' rainfall, together with the introduction of a visual tree assessment program.[2033]

Submissions

Origin considered that Energex could have provided more information on whether the increases in vegetation management costs are based solely on a change in rainfall patterns or if vegetation management goals will be met more quickly as a result of increases in vegetation management spending.[2034]

[2031] Energex, *Regulatory proposal*, July 2009, p. 184 and PB, *Report – Energex*, October 2009, p. 91.
[2032] Energex, *Regulatory proposal*, July 2009, p. 187.
[2033] Energex, *Regulatory proposal*, July 2009, pp. 186–187.
[2034] Origin, *Queensland DNSPs*, August 2009, p. 6.

Consultant review

PB's top down analysis of this activity involved backing out the real cost escalation built into the forecasts and comparing them to the current regulatory control period expenditures. PB noted a $4.8 million step change in real terms between 2009–10 and 2010–11. PB concluded that the primary reason for the additional expenditure related to the proposed introduction of reduced trimming cycles on low voltage urban lines. PB noted Energex's plan to bring all trimming cycles in urban areas onto the same 15 month cycle.[2035]

PB indicated that Energex had received improvement notices from the Electricity Safety Office (ESO) to maintain statutory clearances.[2036] PB recommended that the proposed vegetation expenditure be accepted with no changes in order to fulfil regulatory and legislative obligations.[2037]

AER considerations

The AER notes the step change in vegetation management expenditure in Energex's regulatory proposal. The increase in Energex's vegetation management spending is driven by Energex's legislative obligation to keep low voltage mains free of vegetation.[2038] Energex stipulated that reducing the trimming cycle for low voltage spurs in urban areas will increase costs by $10.2 million between 2009–10 and 2010–11.[2039] However the cost increase included in Energex's regulatory proposal is only $6.9 million.[2040] The AER considers this difference reflects expected cost savings in vegetation management, arising from competitive tendering of the vegetation management contract, and likely economies of scale.[2041]

The AER also investigated Energex's claim that part of the step change in vegetation management is directly attributable to a return to 'more typical rainfall patterns' for Brisbane in 2008. The AER confirmed this claim by reviewing rainfall data for Brisbane in 2008 from the Bureau of Meteorology.[2042] Through this process, the AER noted that for the 2008 calendar year, Brisbane received 1241mm of rain, compared to an average of 1146mm.

In addition, the AER notes that Energex has been receiving infringement notices from the ESO in relation to vegetation clearance zones around lines and wires.[2043] The AER accepts that Energex is required to fulfil these legislative obligations, and accepts vegetation management opex needs to increase to rectify the problems identified.

[2035] PB, *Report – Energex*, October 2009, p. 106.
[2036] PB, *Report – Energex*, October 2009, p. 106.
[2037] PB, *Report – Energex*, October 2009, p. 107.
[2038] Energex, email response, PB.EGX.VP.28, 24 July 2009, p. 1.
[2039] Energex, email response, PB.EGX.VP.28, 24 July 2009, pp. 1–2.
[2040] Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2.
[2041] Energex, PB.EGX.VP.43, 10 August 2009, p. 1.
[2042] Bureau of Meteorology, *Queensland and Brisbane monthly climate summary archive*, <http://www.bom.gov.au/climate/current/month/qld/archive/>.
[2043] Energex, email response, PB.EGX.VP.28, 24 July 2009.

The AER considers that the forecasting methodology employed by Energex is likely to produce a reasonable estimate, and as such the AER considers that the opex forecast for vegetation management is prudent and efficient.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed vegetation management expenditure reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.5.5 Emergency response/storms

Regulatory proposal

Energex stated the emergency response/storms opex program involved repair of damaged equipment and all storm related repairs. Due to the unpredictable nature of storms, Energex used a long term average number of storm events, over eight years, to estimate the opex for this category.[2044]

Total emergency response/storms expenditure is forecast to be $45 million over the next regulatory control period, which represents a real decrease of 6 per cent compared to the current regulatory control period.[2045]

Consultant review

PB's top down analysis of this activity involved backing out the real cost escalation built into the forecasts and comparing them to the current period expenditures. This indicated that the annual forecasts before application of the real cost escalators is essentially the average annual expenditure in the current regulatory control period. PB noted that Energex had not incorporated network growth into its emergency response/storms opex forecasts. PB stated that offsetting the increased exposure to emergency response/storms costs from network growth was the benefits of the large vegetation management program [2046] PB recommended that Energex's emergency response/storms opex forecast should be accepted with no change.[2047]

AER considerations

Expenditure on emergency response/storms is extremely volatile and as such the AER considers that the use of average historical data is an appropriate method of forecasting emergency response/storms opex (the forecasts were based on an eight year historical average up to 2007–08).[2048] The AER considers that this forecasting methodology is likely to produce a prudent estimate of the volume of work resulting from emergency response/storms.

[2044] Energex, *Regulatory proposal*, July 2009, p. 167 and 187.
[2045] Energex, *Regulatory proposal*, July 2009, p. 187.
[2046] PB, *Report – Energex*, October 2009, p. 108.
[2047] PB, *Report – Energex*, October 2009, pp. 108–109.
[2048] Energex, email response, PB.EGX.VP.40, 24 July 2009.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed emergency response/storms expenditure reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.6 Other operating costs

Energex's other operating costs category includes meter reading, customer services, demand side management (DSM) initiatives, advertising, seminar and training expenses, sponsorships and other general expenses.

Regulatory proposal

Table I.4 shows Energex's forecast other operating costs for the next regulatory control period.

Table I.4: Energex forecast other operating costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Meter reading	14.6	15.2	15.8	16.5	17.1	79.2
Customer services	21.0	21.9	22.4	23.1	23.6	111.9
DSM initiatives	24.6	23.2	25.3	30.6	23.2	126.9
Levies	8.6	8.9	9.2	9.5	9.9	46.1
Other support costs	19.2	18.8	19.3	18.6	17.9	93.8
Total other operating costs	88.0	87.9	92.0	98.2	91.7	457.7

Source: Energex, *Regulatory Proposal*, July 2009, RIN proforma 2.2.2.
Note: Totals may not add due to rounding.

Other operating costs are forecast to be $458 million over the next regulatory control period, compared to $364 million in the current regulatory control period. This represents a 26 per cent real increase. Other operating costs account for approximately 33 per cent of Energex's total forecast opex for the next regulatory control period.

I.3.6.1 Meter reading

Regulatory proposal

Energex stated that its meter reading opex category was comprised of three activities:[2049]

- meter reading – physical visits to customer premises every three months (monthly for high use customers). This activity is subject to regular competitive tendering processes to ensure competitive pricing

[2049] Energex, *Regulatory proposal*, July 2009, p. 168.

- data processing and warehousing – collecting interval data for type 5–7 customers, and converting data to consumption reads for network billing
- network billing – generating invoices and providing a monthly statement to retailers.

Total meter reading expenditure is forecast to be $79 million in the next regulatory control period, which represents a real increase of 6 per cent compared to the current regulatory control period.[2050] Energex stated that the primary drivers behind the increase in meter reading costs were higher contractor rates and network growth.[2051]

Consultant review

PB's top down analysis of this activity involved backing out the real cost escalation built into the forecasts and comparing them to the current period expenditures. This indicated that the annual forecasts before application of the real cost escalators are slightly lower on average in the next period compared to the current period. PB also noted that the largest component of meter reading costs is meter reading activities, which are subject to a periodic tendering process to ensure current market costs and service levels are maintained. The meter reading forecasts were based on forecast customer numbers, which explained the increasing expenditure trend in the next regulatory control period.[2052]

PB recommended that the meter reading opex forecasts should be accepted with no change.[2053]

AER considerations

The AER notes PB's findings that the majority of costs associated with meter reading are directly related to the physical reading of meters. This activity is undertaken by contractors, with the contracts being subject to a periodic competitive tendering process to ensure that the contract prices are competitive.[2054]

The AER compared the average costs for the next regulatory control period with the average costs for the current regulatory control period. In real terms, with real cost escalations backed out of the forecasts, the average for the current regulatory control period is slightly higher than the next regulatory control period. The AER notes that metering expenditure is slightly higher in the final year of the current regulatory control period. However, even when the final year is excluded, the average for the current regulatory control period is still above the unescalated metering forecasts for the next regulatory control period.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed meter reading expenditure reasonably reflects the

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[2050] Energex, *Regulatory proposal*, July 2009, p. 187.
[2051] Energex, *Regulatory proposal*, July 2009, p. 188.
[2052] PB, *Report – Energex*, October 2009, p. 110.
[2053] PB, *Report – Energex*, October 2009, p. 110.
[2054] PB, *Report – Energex*, October 2009, p. 110.

opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.6.2 Customer services

Regulatory proposal

Customer service expenditure is related to the contact centre and field response costs, resulting from customer requests in relation to loss of supply, cold water concerns and network related meter queries. Energex stated that customer service demand is influenced by seasonal variations, with cold winters and hot summers incurring increased field costs.[2055] Energex based its customer service opex forecasts on a more typical weather pattern than that which occurred in the 2007–08 base year.[2056]

Energex stated forecast customer service opex also includes expenditure related to guaranteed service level (GSL) payments, in particular a 30 per cent increase in GSL payments that is to apply from 1 July 2010, as decided by the QCA.[2057]

Total customer service expenditure is forecast to be $112 million in the next regulatory control period, which represents a real increase of 34 per cent compared to the current regulatory control period.[2058] Energex stated that the primary driver behind the increase in customer service expenditure was the establishment of new call centres after Energex's retail business was sold.[2059]

Consultant review

PB noted the step change in customer service costs in 2008–09 and the further step change in 2009–10 are due to the loss of cooperative interaction between the Energex electricity network, retail electricity and gas businesses, as the retail electricity and gas businesses were sold. Subsequent to that sale, Energex had to develop and commission a Customer Management System (CMS), Interactive Voice Response (IVR) and a call centre telephony system suitable for its future requirements.[2060]

The Network Contact Centre, which PB stated accounted for most of the costs in customer service activities, has operated in its present form since April 2008. This was when the transition arrangements associated with the sale were completed.

PB therefore considered that the 2009–10 financial year costs are representative of the full costs associated with the customer services activity. After backing out the real cost escalations, PB advised that the annual real forecasts are constant at the same

[2055] Energex, *Regulatory proposal*, July 2009, p. 185.
[2056] Energex, *Regulatory proposal*, July 2009, pp. 185–186
[2057] Energex, *Regulatory proposal*, July 2009, p. 186 and QCA, *Review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010, Final decision*, April 2009.
[2058] Energex, *Regulatory proposal*, July 2009, p. 187.
[2059] Energex, email response, PB.EGX.VP.57, 26 August 2009.
[2060] PB, *Report – Energex*, October 2009, p. 111.

level as the 2009–10 financial year.[2061] On this basis, PB recommended that the opex forecasts for customer services should be accepted without change.[2062]

AER considerations

As part of its analysis of customer services, the AER examined whether any one off establishment costs in relation to the establishment of Energex's contact centre had been included in the opex for the current regulatory control period. Such one off costs would be inappropriate to include in the basis for forecasting future expenditure. Information provided by Energex enabled the AER to confirm that establishment costs were excluded from the derivation of the customer service opex forecasts.[2063]

The AER also notes that PB has confirmed the customer service opex forecasts reflect the expected expenditure in 2009–10, the first year that new customer service arrangements will be fully implemented. Having satisfied itself that one off establishment costs associated with the contact centre were not incorporated, and that the forecasts reflect a reasonable expectation of future expenditure, the AER considers that Energex's customer services opex forecast is likely to be prudent and efficient.

The AER has also reviewed Energex's forecast of GSL payments, and the QCA's recent decision on updating the Minimum Service Standards and GSLs.[2064] GSL payments are incurred when the network service provider fails in its duty to provide a reliable service. In essence, GSL payments are a mechanism designed to encourage the network service provider to deliver a reliable and safe service.

The AER considers that GSL payments, under certain circumstances, may be considered regulatory payments in accordance with section 2E of the NEL. For example, in the circumstances where making a GSL payment for breach of a distribution service standard is more efficient than making the necessary investments to ensure compliance with the distribution service standard, the GSL payment appears to satisfy paragraph (b) of section 2E of the NEL. Where a GSL payment is made for a breach of a service standard that occurs due to business mismanagement rather than efficient planning considerations, that payment is less likely to satisfy the NEL definition of a regulatory payment.

The AER accepts that a prudent and efficient network service provider may incur GSL payments in order to meet efficient planning goals and that such payments represent a regulatory obligation imposed on Energex. As such, the AER considers that it should provide a reasonable opportunity for Energex to recover the efficient costs of satisfying such obligations in accordance with clause 7A(2)(b) of the NEL.

The AER also recognises section 7A(3) of the NEL which indicates that network service providers should be given effective incentives to promote economic efficiency. GSL payments above the efficient level are costs that the AER considers should be incurred by shareholders rather than customers.

[2061] PB, *Report – Energex*, October 2009, pp. 111–112.
[2062] PB, *Report – Energex*, October 2009, pp. 111–112.
[2063] Energex, email response, AER.EGX.30, 21 October 2009.
[2064] QCA, *Review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010, Final decision*, April 2009.

The AER accepts Energex's forecast of GSL payments as efficient, as the forecasts are consistent with its historical levels of GSL payments. The AER notes that the GSL forecast payments have been updated (in real terms) where relevant to reflect revised payment schedules.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed customer service opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.6.3 Demand side management initiatives

Regulatory proposal

Demand management is comprised of nine programs designed to address the balance between supply and demand through non–network alternatives. Energex provided business cases for each program.[2065] The demand management forecasts are derived on the basis of each individual project.

Total demand management expenditure is forecast to be $127 million in the next regulatory control period, which represents a real increase of 115 per cent compared to the current regulatory control period.[2066]

Energex stated its goal, from an electricity infrastructure point of view, is:[2067]

> to achieve better utilisation of network assets so that ultimately this benefit can be passed on to electricity customers, through efficient network prices that reflect the real cost of customer demand.

The real increase in this expenditure category is directly attributable to Energex looking to implement new demand management initiatives in order to achieve its stated goal.

Submissions

The EUAA considered that demand management expenditure must be economically robust, and the AER needs to ensure that the benefit of such expenditure exceeds its cost before allowing for the inclusion of this expenditure in regulatory allowances. Further, the EUAA stated that if demand management expenditure is simply intended to defer growth then the benefits will be unlikely to exceed the costs. The EUAA considered that the AER needed to examine this aspect in detail.[2068]

The QCOSS raised concerns over the demand management initiatives proposed by Energex. The QCOSS's major concern was that a broad brush roll out of demand

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[2065] Energex, *Regulatory proposal*, July 2009, p. 184; and Energex, email response, PB.EGX.VP.51, 10 August 2009.
[2066] Energex, *Regulatory proposal*, July 2009, p. 187.
[2067] Energex, *Regulatory proposal*, July 2009, p. 86.
[2068] EUAA, *Submission to the AER*, 28 August 2009, p. 19.

management initiatives will not serve to avoid or defer network augmentation investment.[2069]

Consultant review

PB's assessment of Energex's demand management initiatives involved obtaining business cases of each program. These business cases included a net present value (NPV) analysis and an evaluation of the forecast impact on peak demand. The nine demand management programs identified through PB's analysis are:[2070]

- air conditioning direct load control (DLC)
- pool filtration direct load control
- conversion of hot water system tariffs
- hot water optimisation
- reward based tariffs
- centre of excellence
- commercial and industrial demand management
- energy conservation communities
- demand and energy data capture and analysis.

PB reviewed the NPV analysis and the forecast impact on peak demand. PB considered that a positive NPV indicates that the benefits outweigh the project costs, and considered it important that all accepted projects should have an identifiable impact on peak demand.[2071] PB recommended that the AER accept all demand management projects except for the demand and energy data capture and analysis program, which had a negative NPV and no reduction on peak system demand.[2072]

Table I.5 shows PB's proposed expenditure for demand management.

[2069] QCOSS, *Response to Queensland Distribution Network Service Providers' Regulatory Proposal*, August 2009, p. 5.
[2070] Energex, email response, PB.EGX.VP.51, 10 August 2009, p. 2.
[2071] PB, *Report – Energex*, October 2009, p. 115.
[2072] PB, *Report – Energex*, October 2009, p. 115.

Table I.5: PB's recommended demand management expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Demand management initiatives	24.6	23.2	25.3	30.6	23.2	126.9
PB adjustments	–2.2	0	0	0	0	–2.2
PB recommended DSM initiatives	22.4	23.2	25.3	30.6	23.2	124.7

Source: PB, *Report – Energex*, October 2009, p. 116.
Note: Totals may not add due to rounding.

AER considerations

The AER examined the DSM business plans and cost/benefit analyses that were conducted by Energex.[2073] The AER considers that the combination of NPV analysis and a study of the net reduction in network usage is an appropriate method of judging the relative efficiency, as well as the costs and benefits, of demand management initiatives. The AER considers this method addresses the EUAA's concerns about the AER investigating the costs and benefits of each demand management proposal. The AER also considers that demand management projects that record a negative NPV, and have no net reduction on peak demand, should not be accepted.

The AER considers Energex's demand management initiatives are efficient with the exception of the demand and energy data capture and analysis program. That program has a negative NPV and does not reduce peak system demand. The AER considers that it is important to allow DNSPs to find non–network alternatives to meet demand, and considers that Energex's other demand management initiatives are economically justifiable.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other supporting information, the AER is not satisfied that Energex's proposed demand management opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed demand management opex by $2.2 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

I.3.6.4 Levies

Regulatory proposal

Energex's forecast levies expenditure is related to legislative payments required under the *Electrical Safety Act (2002)* (payments to the Electrical Safety Office (ESO)) and the *Queensland Competition Authority Amendment Regulation (No.1) 2003* (payments

[2073] Energex, email response, PB.EGX.VP.50, 10 August 2009.

to the QCA).[2074] The ESO levy amount has been forecast based on the methodology mandated by the *Electrical Safety Act (2002)* and the Department of Employment and Industrial Relations. The QCA levy is forecast based on the *Queensland Competition Authority Amendment Regulation (no.1) 2003*. Increases in expenditure for this category are directly attributable to changes in these methodologies.[2075]

Total levies expenditure is forecast to be $46 million in the next regulatory control period, which represents a real increase of 31 per cent compared to the current regulatory control period.[2076]

AER considerations

The AER examined the manner in which the levies had been forecast. Energex stated that the levy paid to the ESO had been calculated using the methodology published by the Department of Employment and Industrial Relations in February 2009.[2077] Energex stated that this levy is calculated independently by the ESO, and then forwarded to Energex for payment.[2078] The AER obtained a copy of this methodology and examined whether the methodology had been applied correctly.[2079] As a result of this process, the AER is satisfied that Energex has correctly applied the Department of Employment and Industrial Relations' levy calculation methodology in developing its ESO levy forecast.

The AER also investigated whether the QCA levy had been correctly applied to Energex's opex forecasts. Energex advised that the QCA levy is comprised of fixed and variable components based on regulated revenue.[2080] Based on its review of the information provided by Energex, the AER is satisfied that the QCA levy forecasts were appropriately derived.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other supporting information, the AER is satisfied that Energex's proposed levies expenditure reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

I.3.6.5 Other support costs

Regulatory proposal

Energex advised that the other support costs opex includes the following costs:

- advertising and marketing
- sponsorships

[2074] Energex, *Regulatory proposal*, July 2009, p. 170.
[2075] Energex, *Regulatory proposal*, July 2009, pp. 187–188.
[2076] Energex, *Regulatory proposal*, July 2009, p. 187.
[2077] Energex, *Regulatory proposal*, July 2009, pp. 170–171.
[2078] Energex, email response, AER.EGX.30, 16 October 2009, p. 6.
[2079] Energex, email response, AER.EGX.30, 16 October 2009, p. 6.
[2080] Energex, email response, AER.EGX.30, 16 October 2009, p. 6.

- property and operating costs
- seminar and training expenses
- other general expenses.

Energex further advised that other general expenses included stationery costs, postage and courier costs and audit fees.[2081] Energex stated that the other support costs forecasts have been based on historical trends.[2082] A breakdown of other support costs was not provided as part of Energex's regulatory proposal.

AER considerations

The AER reviewed Energex's other support costs to determine if they were related to the provision of standard control services, as required by clause 6.5.6(a) of the NER. The AER also sought further information from Energex to ensure that no costs relevant to unregulated activities were included in this expenditure category.[2083]

Energex was unable to provide a breakdown of other support costs that were allocated to the regulated business.[2084] However, Energex advised that, in line with Energex's cost allocation method (CAM), approximately 1.37 per cent of the costs above were allocated to the unregulated business.[2085] Energex's proposed other support costs are shown in table I.6.

Table I.6: Energex other support costs by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Advertising and marketing	3.3	2.9	3.3	2.9	2.8	15.2
Sponsorships	1.9	1.9	1.9	1.9	1.8	9.3
Property and operating costs	5.5	5.4	5.5	5.2	5.0	26.7
Seminar and training expenses	3.8	3.8	3.8	3.8	3.7	19.0
Other general expense	5.0	5.0	5.0	5.0	4.8	24.9
Total	19.5	19.0	19.5	18.8	18.2	95.1

Source: Energex, email response, AER.EGX.30, 22 October 2009, p. 9.
Note: This table shows figures for both Energex's regulated and unregulated businesses. Energex advised that approximately 1.37 per cent of costs in the table above were allocated to unregulated services.

The AER considers that on the basis of the information provided, property and operating costs, and seminar and training expenses are related to the provision of

2081 Energex, *Regulatory proposal*, July 2009, p. 172.
2082 Energex, *Regulatory proposal*, July 2009, p. 172
2083 AER, email response, AER.EGX.30, 21 October 2009.
2084 Energex, email response, AER.EGX.30, 22 October 2009, p. 9.
2085 Energex, email response, AER.EGX.30, 22 October 2009, p. 13.

standard control services by Energex and have been appropriately allocated in accordance with Energex's CAM.

The AER also considers that advertising and marketing expenditure related to the provision of safe electrical services to the public can also be attributed to standard control services. The AER notes that as part of its legislative compliance, Energex may be required to embark on advertising campaigns that provide public safety messages. The AER considers that expenditure to satisfy initiatives or comply with legislative obligations such as these are likely to be consistent with the opex objectives, in particular, section 6.5.6(c)(2) of the NER.

However, in general the AER considers that sponsorship activities do not represent expenditure required to comply with the opex objectives. The AER considers that sponsorships are generally designed to increase brand awareness or demonstrate community support. Such activities may provide a benefit to the community but do not relate to the provision of standard control services by regulated electricity DNSPs, nor do they relate to the opex objectives.

The AER considers that Energex has not demonstrated how its $9.1 million[2086] forecast sponsorship expenditure is required to achieve the opex objectives, nor has it outlined how it is relevant to the provision of standard control services. The AER is not satisfied that this forecast level of expenditure is efficient and prudent expenditure.

In terms of the other general expense category shown in table I.6 above, Energex provided a disaggregation, as shown in table I.7 below.

Table I.7: Energex other general expenses ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Stock write offs	0.3	0.3	0.3	0.3	0.3	1.7
Audit fees	0.6	0.6	0.6	0.6	0.6	2.9
Stationery, postage and couriers	3.7	3.7	3.7	3.7	3.6	18.5
Dial before you dig contribution	0.2	0.2	0.2	0.2	0.2	0.9
General	0.2	0.2	0.2	0.2	0.2	0.9
Total	5.0	5.0	5.0	5.0	4.8	24.9

Source: Energex, email response, AER.EGX.30, 22 October 2009, p. 10.

The AER considers that on the basis of information provided, with the exception of stock write offs, the components of other general expenses are related to the provision

[2086] The figure of $9.1 million for this category is derived by applying Energex's advised proportion of allocating 1.37 per cent of costs for other support costs to unregulated services.

of standard control services by Energex and have been appropriately allocated in accordance with Energex's CAM.

However, the AER considers that Energex will have been compensated for the cost of purchasing stock or goods through the previous opex allowances approved by the QCA. Accordingly the AER considers that stock write offs do not have an incurred cost for regulatory purposes, and as such should be excluded from the regulatory allowances.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other supporting information, the AER is not satisfied that Energex's proposed other support costs reasonably reflect the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed other general expenses opex by $10.8 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

Table I.8 shows the AER's adjustments to the other support costs category.

Table I.8: AER's adjustment to Energex's other support costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Other support costs	19.2	18.8	19.3	18.6	17.9	93.8
AER adjustments for sponsorships and stock write offs	–2.2	–2.2	–2.2	–2.2	–2.1	–10.8
Total	17.0	18.6	17.1	16.4	15.8	84.9

Note: Adjustments have taken into account Energex's statement that it has allocated 98.63 per cent of this cost category to regulated services.
Totals may not add due to rounding.

I.3.6.6 Shared costs – ICT systems

Energex regulatory proposal

The majority of Energex's expenditure on information and communications technology is delivered under its arrangement with SPARQ Solutions (SPARQ), for which Energex is charged service fees. These service fees charged by SPARQ are treated as shared costs by Energex, which are discussed in section F.5.4.6 of appendix F. The AER notes that Energex allocates shared costs in accordance with the AER's approved CAM, which results in approximately 23 per cent of ICT service fees allocated to opex.

AER conclusion

The AER's detailed considerations of Energex's proposed ICT overheads are set out at section F.5.4.6 of appendix F.

For the reasons discussed, and as a result of the AER's analysis of Energex's regulatory proposal and PB's report and other supporting information, the AER is not satisfied that Energex's forecast of ICT overheads reasonably reflect the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed allocation of shared ICT costs to opex by $2.2 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

Table I.9: AER conclusion on ICT shared costs – SPARQ ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Reduction in expensed ICT overheads	–0.1	–0.6	–0.5	–0.4	–0.5	–2.2

Source: PB, *Report – Energex*, October 2009, p. 17.
Note: Reductions in indirect costs allocated to capex and opex are based on the 77:23 allocation of indirect costs to capex and opex that results from Energex's CAM.

I.4 AER conclusion

The AER has reviewed Energex's proposed forecast controllable opex allowance and, for the reasons set out in this appendix, is not satisfied that the proposed forecast opex allowance reasonably reflects the opex criteria under clause 6.5.6(c) of the NER. In reaching this conclusion, the AER has had regard to the opex factors set out in clause 6.5.6(e) of the NER. In particular the AER considers:

- the proposed controllable opex does not reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives
- the proposed controllable opex does not reflect the efficient costs that a prudent operator in the circumstances of Energex would require to achieve the opex objectives
- the proposed controllable opex has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the opex criteria.

As the AER is not satisfied that the controllable opex allowance reasonably reflects the opex criteria, under clause 6.5.6(d) of the NER the AER must not accept the controllable opex proposed by Energex. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the opex for Energex over the next regulatory control period which it is satisfied reasonably reflects the opex criteria, taking into account the opex factors. Allowing for the adjustments listed above, the AER's estimate of controllable opex for Energex is $1681 million, as set out in table I.10.

Table I.10: AER's draft decision on Energex's controllable opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed controllable opex	324.5	330.0	340.4	351.6	349.2	1695.7
Adjustment for DSM initiatives	–2.2	0	0	0	0	–2.2
Adjustment to other support costs	–2.2	–2.2	–2.2	–2.2	–2.1	–10.8
Adjustment to overheads	–0.1	–0.6	–0.5	–0.4	–0.5	–2.2
Total adjustments	–4.5	–2.8	–2.7	–2.6	–2.7	–15.3
AER controllable opex allowance	320.0	327.2	337.7	349.0	346.6	1680.5

Note: Totals may not add due to rounding. Does not include the AER's revised input cost escalators.

J. Ergon Energy controllable operating expenditure

J.1 Introduction

This appendix is to be read in conjunction with chapter 8 of this draft decision. It sets out the AER's detailed considerations and conclusions on Ergon Energy's proposed controllable opex allowance for the next regulatory control period. The regulatory requirements and the general approach used by the AER to assess Ergon Energy's opex proposal are set out in chapter 8 of this draft decision.

The AER's review of controllable opex is undertaken separately to its review of input cost escalators (section 8.8.6 of this draft decision). The impact of revisions to input cost escalators is therefore not factored into the AER conclusions presented on controllable opex. The consolidated impact of all adjustments required by the AER (controllable opex, uncontrollable opex, capex/opex tradeoffs, and input cost escalation) is set out in the AER conclusions (section 8.9 of this draft decision).

J.2 Ergon Energy regulatory proposal

Table J.1 sets out Ergon Energy's current and forecast controllable opex by cost category.

Table J.1: Ergon Energy's controllable opex by category ($m, 2009–10)

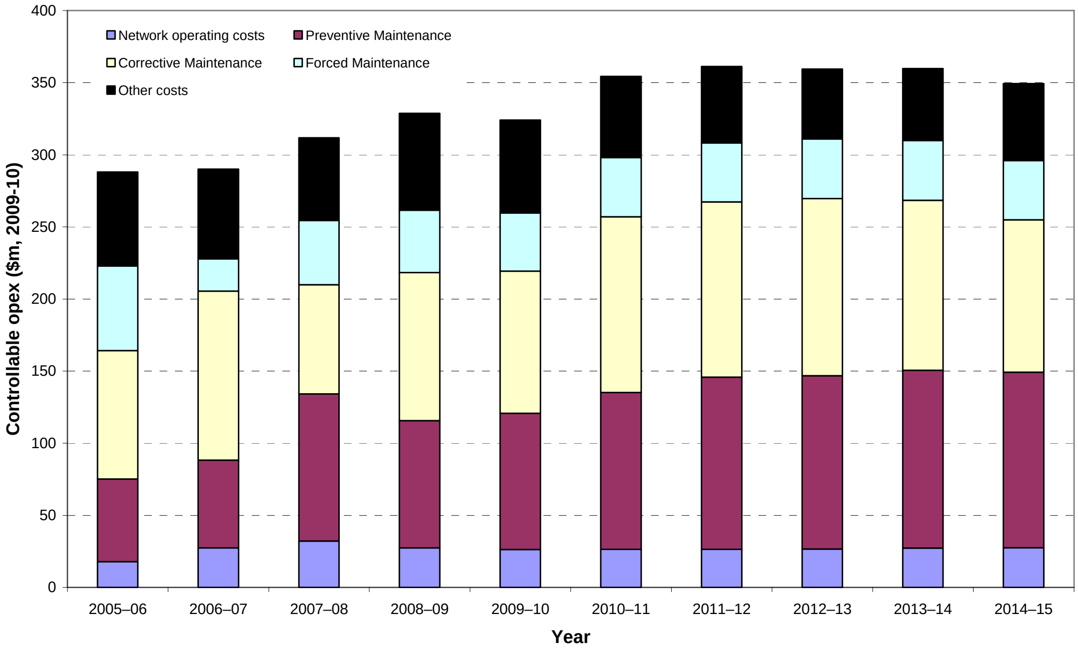
Category	Actual			Estimated		Forecast				
	05–06	**06–07**	**07–08**	**08–09**	**09–10**	**10–11**	**11–12**	**12–13**	**13–14**	**14–15**
Network operations	18.4	28.0	33.5	28.0	26.2	26.4	26.3	26.7	27.2	27.5
Network maintenance	211.2	205.4	231.7	240.0	233.5	271.7	281.9	284.3	282.7	268.4
Other opex	67.1	63.8	59.8	68.8	64.3	67.9	69.1	70.2	72.4	74.3
Total controllable opex[a]	296.7	297.2	325.0	336.9	324.0	365.9	377.3	381.2	382.3	370.2

Source: Ergon Energy, *Regulatory proposal*, July 2009, pp. 259 (nominal converted to real $2009–10), 263, 305–306.

(a) Total controllable opex excludes self insurance ($21.5 million), equity raising costs and debt raising costs ($94.1 million). These elements of total opex are reviewed in chapter 8 of this draft decision.

Figure J.1 shows Ergon Energy's actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

Figure J.1: Ergon Energy's actual and forecast controllable opex ($m, 2009–10)



Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN opex pro forma.

The total proposed controllable opex of $1877 million in the next regulatory control period is 19 per cent higher than the estimated controllable opex of $1580 million ($2009–10) in the current regulatory control period. Ergon Energy indicated that the key drivers of increased controllable opex are:[2087]

- more frequent and rigorous inspection regimes with flow on effects for corrective maintenance costs
- asset growth and input cost escalation
- increased work in vegetation maintenance, access track repair and pole top inspections.

J.3 Issues and AER considerations

J.3.1 Forecasting methodology

Regulatory proposal

Ergon Energy used both baseline/scope change and bottom up methodologies to forecast its opex for the next regulatory control period.

Ergon Energy stated that its baseline/scope change approach involved using 2007–08 actual opex as the baseline then making adjustments for abnormalities and workload growth. The amended baseline expenditure was then escalated to forecast opex

[2087] Ergon Energy, *Regulatory proposal*, July 2009, pp. 27–38.

requirements in the next regulatory control period. Ergon Energy stated it used the baseline/scope change approach to forecast opex in the following categories:[2088]

- network operations
- corrective maintenance and components of forced maintenance
- other controllable opex.

Ergon Energy used a bottom up process for deriving cost estimates where it considered that the baseline/scope change approach did not provide efficient estimates for specific components of opex. The bottom up approach involved multiplying quantities of specified work by the relevant unit rates for the specified work. Ergon Energy advised that the unit rates used were based on actual costs or historical costs.[2089] It used the bottom up approach to derive forecast for preventative maintenance and components of forced maintenance.[2090] The spreadsheets used in its models were independently verified by PriceWaterhouseCoopers (PwC).[2091]

Each of the categories of expenditure was escalated for increases in input costs and network growth. To escalate base year expenditures, Ergon Energy used Sinclair Knight Mertz (SKM) labour and commodity rates to model the impact of future cost drivers on all components of its base year expenditure.[2092]

Ergon Energy stated that its opex forecasts incorporated business as usual costs as well as incremental items based on scope changes in work activity.[2093] Ergon Energy allowed for a 3 per cent annual productivity improvement in its opex forecasts.[2094]

Ergon Energy submitted that it can successfully deliver the system expenditure forecasts for standard control services for the next regulatory control period. Allowing for the 3 per cent annual productivity improvement, Ergon Energy forecast the delivery of its expenditure program requires an average annual system workforce growth of about 6.5 per cent, with a peak annual growth of about 11 per cent in 2010–11.[2095]

Capex/opex trade off

Ergon Energy stated that there was a strong relationship between replacement capex and its preventative maintenance program.[2096] It submitted that asset replacement carried out as a result of preventative maintenance inspections and defect identification generally leads to reduced corrective and forced maintenance activities. Conversely, Ergon Energy stated a reduction in defect expenditure would increase the

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[2088] Ergon Energy, *Regulatory proposal*, July 2009, pp. 265, 276–277, 279, 281.
[2089] Ergon Energy, email to PB, AER-PB Q.VP.31, 31 July 2009, confidential.
[2090] Ergon Energy, *Regulatory proposal*, July 2009, pp. 267–268, 276–277, 328–330.
[2091] Ergon Energy, *Regulatory proposal*, July 2009, Attachment AR003c, Overview of Regulatory Proposal Model, 18 June 2009, p. 2, confidential.
[2092] Ergon Energy, *Regulatory proposal*, July 2009, pp. 78, 273–274, 276–277.
[2093] Ergon Energy, *Regulatory proposal*, July 2009, pp. 266, 269, 274, 277.
[2094] Ergon Energy, *Regulatory proposal*, July 2009, p. 29.
[2095] Ergon Energy, *Regulatory proposal*, July 2009, pp. 29, 349; and Ergon Energy, Q.AER.ERG.27.07, 22 October 2009,confidential.
[2096] Ergon Energy, *Regulatory proposal*, July 2009, p. 196.

risk of asset failure, leading to an increase in corrective and forced maintenance activities.[2097]

Consultant review

PB considered that the methodology used by Ergon Energy was pragmatic and generally an accurate approach to forecasting opex.[2098]

PB noted that the approach was aligned with Ergon Energy's business asset management framework. PB stated that the policies, documentation and modelling align to support the asset management approach. It noted that Ergon Energy's forecasting methodology was comprehensive and transparent. Further PB considered it reflected the needs of the business in the current environment.[2099]

While the forecasting methodology was regarded as reasonable, PB was unable to confirm whether the calculations performed in the model produced robust and accurate results as PB noted the spreadsheets belonging to the models were not integrated and linked. As a result, it could not conduct sensitivity analysis or review the accuracy of the models.[2100]

PB stated it relied upon the review undertaken by PwC to increase its confidence in the accuracy and robustness of Ergon Energy's modelling.[2101]

Capex/opex trade off

PB noted that Ergon Energy did not explicitly incorporate any capex/opex trade off adjustments as part of its preventative or corrective maintenance opex forecasts. PB considered that a reduction should be made to opex forecasts as Ergon Energy's large replacement capex program in the next regulatory control period should reduce the need to carry out opex activities.[2102] Accordingly, PB undertook its own calculations and recommended a reduction of $9.7 million ($2009–10) in the proposed preventative and corrective maintenance forecast opex to account for capex/opex interactions. PB used a top down financial ratio methodology to calculate this amount.[2103]

Issues and AER considerations

The AER considers that opex forecasts can be prepared using a baseline/scope change methodology and/or a bottom up approach, and notes Ergon Energy applied both of these methods to elements of its opex forecasts.

In both cases the key issues for the AER are whether the methodology has been correctly applied, and whether the assumptions and data used to develop the forecasts are reasonable and verifiable. The AER has considered the assumptions and data in its

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[2097] Ergon Energy, *Regulatory proposal*, July 2009, p. 196.
[2098] PB, Report – Ergon Energy, October 2009, pp. 109–110.
[2099] PB, Report – Ergon Energy, October 2009, p. 144.
[2100] PB, Report – Ergon Energy, October 2009, p. 109.
[2101] PB, Report – Ergon Energy, October 2009, p. 109.
[2102] PB, Report – Ergon Energy, October 2009, pp. 116–118. See chapter 7 of this draft decision for further details on the capex program.
[2103] PB, *Report – Ergon Energy*, October 2009, pp. 116–117.

review of specific components of the opex forecasts in section J.3.2–J.3.7 of this appendix.

The AER notes that PB was unable to provide an assessment of whether the forecasting methodology was correctly applied by Ergon Energy. However, Ergon Energy did provide a copy of the findings of a review of its modelling undertaken by PwC. The AER notes the PwC report was not an audit of Ergon Energy's models, however the report confirmed the calculations in the models and links from the input models.[2104]

PwC advised Ergon Energy of a number of minor issues in relation to the models and data linkages but was not asked to review the updated models after those issues were addressed by Ergon Energy. PwC also did not review if changes in assumptions correctly flow through to the results.

As the AER has been unable to review Ergon Energy's complete opex forecasting models, its acceptance of the modelling outcomes is based on the assurances provided by PwC. The AER considers that the onus lies upon Ergon Energy to ensure that its models are accurate and free from material error. Should Ergon Energy or the AER become aware that the models do not provide accurate results the distribution determination may be revoked and substituted to correct for the modelling errors.[2105]

Capex/opex trade off

The AER notes Ergon Energy recognised strong interactions between various categories of opex and capex.[2106] However the AER also notes PB's statement that it found no evidence to suggest that a capex/opex trade off is explicitly taken into account in the development replacement programs, or preventative, corrective and forced maintenance forecasts.

The modelling undertaken by Ergon Energy explicitly provides for opex increases associated with growth capex, in that there is an escalation factor derived from the growth in the asset base applied to all asset classes. The AER would expect to see explicit modelling of forecast reductions in opex associated with replacement capex. This would be on the basis that replacement capex should be targeted at poor performing or failure prone assets, hence reducing opex requirements.

Given that Ergon Energy has not provided any specific information describing how the capex/opex trade off is taken into account in its modelling, the AER considers the forecast opex is likely to be greater than the efficient amount required by Ergon Energy to meet the opex objectives.

The AER notes that PB recommended an opex saving for preventative and corrective maintenance to take account of Ergon Energy's forecast 243 per cent real increase in replacement capex. PB applied a total opex cost saving of 20 per cent to a ratio of

[2104] PwC, Financial model: agreed upon procedures, 22 June 2009, p. 3, confidential.
[2105] NER, clause 6.13.
[2106] Ergon Energy, *Regulatory proposal*, July 2009, p. 310.

asset replacement capex and the replacement value of the RAB.[2107] Using this methodology PB recommended a reduction of $9.7 million ($2009–10).[2108]

The AER considers that PB has provided a model that Ergon Energy will be able to replicate in order to explicitly forecast opex cost savings arising from increased replacement capex. The AER considers that a prudent operator in the circumstances of Ergon Energy would model a capex/opex trade off in its expenditure forecasting, and in the absence of providing such information in its regulatory proposal, must replicate the PB model to estimate the opex reduction. For this reason, the AER requested Ergon Energy to adjust its modelling to explicitly account for the estimated capex/opex trade off using the methodology applied by PB.[2109] The AER requested Ergon Energy use the adjusted replacement capex forecasts set out in chapter 7 of this draft decision.

Ergon Energy advised that the capex/opex adjustment results in a reduction of $9.9 million ($2009–10) to the forecast controllable opex for the next regulatory control period. This amount comprises $5.0 million reduction in preventative maintenance opex and $4.9 million in corrective maintenance opex.[2110]

AER conclusion

The AER accepts the general modelling framework described by Ergon Energy as a pragmatic approach to forecasting opex for the next regulatory control period.

However, the AER does not consider that Ergon Energy has suitably accounted for the impact of the significant replacement capex program on preventative and corrective maintenance.

For the reasons discussed, as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER considers that reducing Ergon Energy's proposed controllable opex by $9.9 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

J.3.2 Efficient base year

Regulatory proposal

Ergon Energy used its 2007–08 opex as the base year to forecast its network operations, corrective maintenance, components of forced maintenance and other operating costs in the next regulatory control period. Ergon Energy stated that it selected 2007–08 as the base year as it provided a sound basis for preparing the opex forecasts.[2111]

[2107] PB, Report – Ergon Energy, October 2009, pp. 116–118.
[2108] PB, Report – Ergon Energy, October 2009, p. 118.
[2109] AER, modelling request, 6 November 2009.
[2110] Ergon Energy, response to AER modelling request PL869c, 13 November 2009 confidential.
[2111] Ergon Energy, *Regulatory proposal*, July 2009, p. 274, 277, 279.

Ergon Energy stated that the main data management system for its opex activities, Ellipse, was introduced in 2006–07. It also stated that it uses data drawn from Ellipse to make resource planning decisions for its capex and opex programs. In relation to the opex program, Ergon Energy stated that it uses data from Ellipse for resource planning for its preventative and corrective maintenance programs.[2112]

Where the baseline/scope change approach was used to estimate costs, Ergon Energy stated that the 2007–08 base year represented business as usual costs for each of the cost categories. The base year opex was adjusted for abnormalities. Scope changes were added to the base year opex if a change in the level of work activity was forecast throughout the next regulatory control period. The adjusted base year opex was then inflated to reflect future price movements.[2113]

Consultant review

PB's review of base year opex is discussed with respect to relevant opex components in the sections of this draft decision on network operations, corrective maintenance, forced maintenance and other operating costs.

Issues and AER considerations

Base year data

The AER considers that the base year opex from which opex forecasts are derived should be representative of efficient expenditure by a DNSP. Ergon Energy used 2007–08 as the base year.

Ergon Energy stated the regulatory accounts for 2007–08 have been audited and provided a copy of the auditors report. The auditors report stated the regulatory statement fairly represented Ergon Energy's financial position and was prepared using the correct cost allocation method.[2114]

In terms of Ergon Energy's total opex in the base year, the AER notes that Ergon Energy overspent against its efficient opex allowance determined by the QCA, by over 10 per cent in nominal terms.[2115] Ergon Energy highlighted the following factors contributed to the overspend in 2007–08:[2116]

- increased maintenance work being undertaken
- higher than forecast labour and contractor costs
- increased overall employee numbers
- a requirement for training expenditure to be completely expensed rather than partially capitalised

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[2112] Ergon Energy, Regulatory proposal, July 2009, p. 268 & 274 and Ergon Energy, AER.ERG.27.06, 20 October 2009, confidential.
[2113] Ergon Energy, *Regulatory proposal*, July 2009, pp. 266, 269, 274, 277.
[2114] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR370c, confidential.
[2115] Ergon Energy, *Regulatory proposal*, July 2009, p. 296, table 76.
[2116] Ergon Energy, email to the AER, Q.AER.ERG.27.01, 20 October 2009, confidential.

- increased network operations expense arising from the implementation of Project LINK
- information communications and telecommunications (ICT) costs being partially expensed rather than fully capitalised
- a change in charging methodology for Electricity Safety Office (ESO) fees.

The AER notes that increased labour costs contributed to Ergon Energy's higher than forecast opex in 2007–08.[2117] The increase in labour costs occurred because of the boom in economic conditions at that time, causing a general tightening of the labour market in Queensland. The increase in operations work volume is also mirrored by Ergon Energy's capex program which was also substantially higher than forecast for the current regulatory control period.

The AER also considers that an increase in work volume arose from increased economic activity in Queensland and Ergon Energy's response to the Electricity Distribution Service Delivery review (EDSD Review). Changes to Ergon Energy's accounting policies also occurred around this time, where costs that were once grouped as part of a shared cost pool were transferred to opex costs. The AER considers these variations to base year opex provide a reasonable justification for the base year opex overspend.

The base year opex is considered to be efficient as it reflects the efficient allowance provided by the QCA, and the overspent opex is considered to have been explained and justified by Ergon Energy.

The 2007–08 data is the most up to date available and has been subject to audit. The AER considers that actual opex in 2007–08 represents efficient base year opex for Ergon Energy.

However, the AER has further reviewed specific components of base year opex in its consideration of opex categories, and has assessed the base year amounts used to derive opex forecasts in its assessment of specific components of opex, in sections J.3.3 to J.3.7 of this draft decision.

Benchmarking

The NER sets out the factors that the AER must consider when assessing whether or not it is satisfied by a DNSP's forecast opex.[2118] In determining whether or not the proposed forecast opex meets the opex criteria, AER must have regard to the operating expenditure factors, which include:[2119]

> benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.

Ergon Energy engaged Benchmark Economics to conduct benchmarking of its operating performance. At the request of PB, Ergon Energy provided the Benchmark

[2117] Ergon Energy, email to the AER, Q.AER.ERG.27.01, 20 October 2009, confidential.
[2118] NER, clause 6.5.6(e)(1)–(10).
[2119] NER, clause 6.5.6(e)(4).

Economics report.[2120] Benchmark Economics found that Ergon Energy was operating above the trend line, which suggests that its opex is relatively high compared to the other DNSPs.

The AER also undertook benchmarking, including ratio analysis and regression analysis of measures of Ergon Energy's 2007–08 opex against other Australian DNSPs.

The AER provided its ratio analysis to PB. PB considered the results and concluded that Ergon Energy's opex forecasts are relatively high when compared to the other businesses. However, it noted several differences in Ergon Energy's business approach and operating environment that may account for the apparent higher costs, including:[2121]

- the treatment of Ergon Energy's ICT costs, which are accounted for as corporate overheads, rather than capex

- the inspection cycle–based approach to preventative maintenance, where efficiencies associated with contemporary condition or performance–based maintenance are not captured

- the considerable issues associated with the large supply area, in the context of: the vegetation management and corridor sites requirements; including the significant rural backlog; the exposure to inclement and volatile weather; and general travel costs

- the general challenges associated with managing an asset that includes a single wire earth return network extending to over 65 000 km in length and servicing only 25 000 customers.

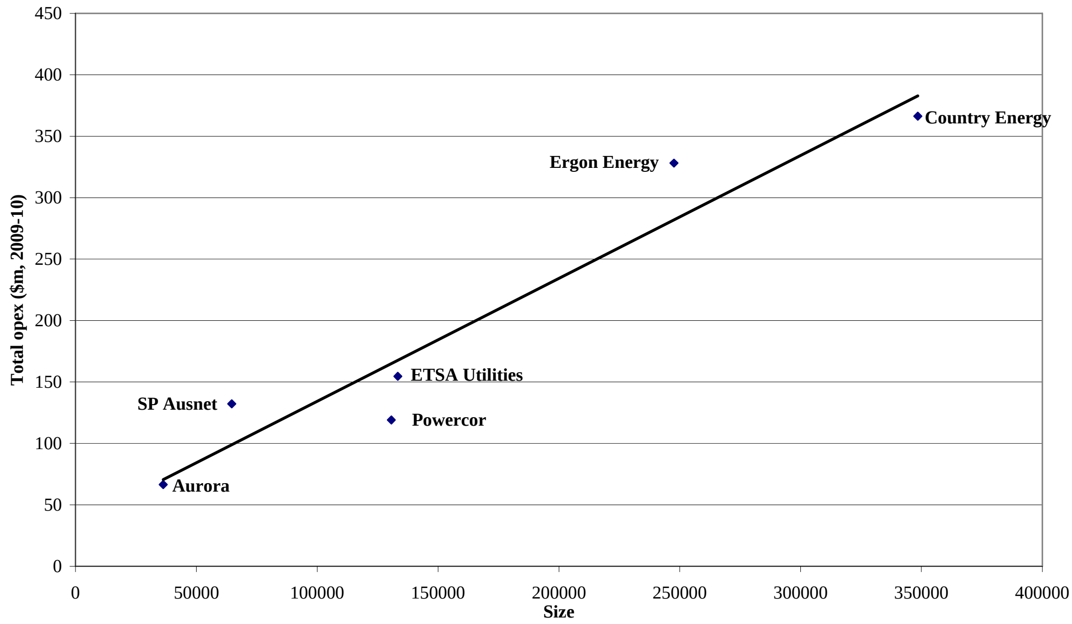
The AER's regression analysis also compared 2007–08 data, and in the case of Ergon Energy, the regression analysis was limited to rural DNSPs in Australia. Figure J.2 shows the results of the AER's regression analysis for rural DNSPs in Australia.

Consistent with the ratio analysis undertaken by the AER, and the Benchmark Economics work, the AER's regression modelling shows that Ergon Energy sits above the regression line, indicating it has relatively high opex in 2007–08, in comparison to other rural DNSPs in the sample. This analysis takes into account factors like the relative size of the DNSPs' networks, and to the extent possible, has used data gathered on a like for like basis.

[2120] Benchmark Economics, internal document, pp. 38–39, Benchmark Economics is an independent economic consulting firm.

[2121] PB, Report – Ergon Energy, October 2009, p. 143.

Figure J.2: Comparative analysis of opex versus size for rural DNSPs ($m, 2009–10)



Source: AER analysis.

The AER also notes the comments of the EUAA, noting the AER's obligation to undertake benchmarking when reviewing opex forecasts.[2122] In particular, the EUAA seemed to be requesting that the opex forecasts be adjusted largely on the basis of benchmarking studies.

However, the issues with the benchmarking work, in terms of the size of the data set, discrepancies in opex definitions and differing regulatory arrangements for comparator DNSPs, limits the use of the benchmarking results as a tool for justifying amendments to opex forecasts. The AER also considers the general limitations of benchmark analysis are recognised by the NER as benchmarking is only one of ten factors that the AER must have regard to, when assessing a DNSP's proposed opex forecast.[2123]

The AER therefore considers that, while benchmarking is a useful high-level analytical tool, its application has necessarily been limited to a top down testing of the more detailed bottom up assessment, informed by due consideration of each of the factors specified in clause 6.5.6(e) of the NER.

As required under clause 6.5.6(e)(4) of the NER, the AER has had regard to benchmark efficient expenditures in assessing Ergon Energy's base year opex and proposed forecast allowances. The AER notes the outcomes of these benchmarking studies, and notes that Ergon Energy's opex appears relatively high in 2007–08 compared to the sample. The AER considers there are reasons for this outcome, and

[2122] EUAA, *Submission to the AER*, p. 1.
[2123] NER, clause 6.5.6.

has considered these factors in its assessment of the prudence and efficiency of Ergon Energy's base year opex, and forecast opex for the next regulatory control period.

AER conclusion

Given Ergon Energy's actual opex in the base year has been verified by an audit of the regulatory information provided to the AER, and the overspend in comparison to the regulatory allowance is explained by prevailing economic conditions and changes in accounting practise; the AER considers it represents an efficient amount from which to forecast opex in the next regulatory control period.

J.3.3 Network operations

Ergon Energy's network operations opex relates to managing and controlling the distribution network from its operations control centres in Townsville and Rockhampton. The major activities include switching and outage coordination, managing network configuration, coordination with the NEM operator, and designing and implementing procedures for the coordination of supply.[2124]

Regulatory proposal

Ergon Energy derived its network operations forecast using a 2007–08 base year extrapolation for all components of network operations expenditure. The base year opex was adjusted downwards for abnormal expenditures relating to implementation costs associated with Project LINK[2125] and switching and control costs associated with system capex programs.[2126]

After adjustments to the base year were completed, Ergon Energy used SKM derived input cost escalators to escalate all components of network operations expenditures.[2127] Ergon Energy stated any further growth in workload for the network operations group is expected to be absorbed through efficiency gains resulting from the realisation of benefits of Project LINK.[2128]

Ergon Energy proposed to spend $134 million ($2009–10) on network operations in the next regulatory control period. Table J.2 shows Ergon Energy's proposed network operating expenditure for the next regulatory control period.

Table J.2: Ergon Energy proposed network operations opex ($m, 2009–10)

	2010–11	2011–12	2011–12	2011–12	2011–12	Total
Network operations	26.4	26.3	26.7	27.2	27.5	134.1

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 69, p. 264.

[2124] Ergon Energy, *Regulatory proposal*, July 2009, p. 265.
[2125] Project LINK refers to the program to enable remote monitoring and control of Ergon Energy's network as a single entity. The program included the construction of two 24 hour control centres in Rockhampton and Townsville, and replacing monitoring technology with a new SCADA system.
[2126] Ergon Energy, *Regulatory proposal*, July 2009, p. 265.
[2127] Ergon Energy, *Regulatory proposal*, July 2009, p. 266.
[2128] Ergon Energy, *Regulatory proposal*, July 2009, pp. 265–266.

Consultant review

PB reviewed Ergon Energy's forecast for network operations, including the information provided in the budgeting process, specific key performance indicators and performance targets. It considered that the base year opex was efficient and that appropriate adjustments had been made to remove abnormalities. PB also concluded that Ergon Energy's proposed network operations opex was prudent and efficient.[2129]

Issues and AER considerations

The AER notes Ergon Energy has forecast its network operations opex by extrapolating its (adjusted) base year expenditures. The forecast has assumed a business as usual scenario for network operations, and likely increases in workload are absorbed through efficiency gains arising from the implementation of Project LINK. The AER also notes PB's conclusion that the forecast expenditure was efficient and prudent.

The AER has reviewed the forecasting methodology and the base year data. The AER considers the baseline/scope change forecasting methodology is appropriate for network operations, given the stable nature of the activities, and clearly identified base year expenditure. The AER considers the adjustments proposed by Ergon Energy are required to ensure the forecast opex reflects the efficient costs.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is satisfied that Ergon Energy's proposed network operations expenditure reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

J.3.4 Network maintenance

Ergon Energy breaks its network maintenance opex into three main categories:

- preventative maintenance
- corrective maintenance
- forced maintenance.

J.3.4.1 Preventative maintenance

Ergon Energy's preventative maintenance opex relates to scheduled inspection and maintenance activities undertaken to minimise the probability of network failure, minimise total asset life costs, meet performance standards and maintain the safety of the network. Ergon Energy stated that it carries out preventative maintenance activities at predetermined intervals or in accordance with prescribed criteria.[2130]

[2129] PB, Report – Ergon Energy, October 2009, pp. 120–121.
[2130] Ergon Energy, *Regulatory proposal*, July 2009, p. 267.

Regulatory proposal

Ergon Energy proposed to spend $594 million ($2009–10) on preventative maintenance in the next regulatory control period. Table J.3 shows Ergon Energy's proposed preventative maintenance opex for the next regulatory control period.

Ergon Energy's Network Assets Replacement Maintenance Capex Opex Summary (NARMCOS) model was used to derive the expenditure forecast using a bottom up methodology.[2131] Ergon Energy stated the NARMCOS model forecasts: the different types of work, volume of work and the total cost required in conducting preventative maintenance work for each of Ergon Energy's asset equipment types, for each year of the five year regulatory control period.[2132]

Ergon Energy stated that its opex forecast reflects its corporate policy on preventative maintenance set out in the document *Preventative maintenance programs for 2010/11–2014/15*. In accordance with its criteria, Ergon Energy's preventative maintenance opex forecast is based on an assessment of the historical performance of its assets, the age and condition of its assets and other factors.[2133]

Table J.3: Ergon Energy proposed preventative maintenance opex ($m, 2009–10)

	2010–11	2011–12	2011–12	2011–12	2011–12	Total
Preventative maintenance	108.8	119.6	120.2	123.4	121.7	593.6

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 70, p. 266.

Consultant review

Preventative maintenance

This section refers to PB's review of non vegetation preventative maintenance which excludes vegetation management and access corridors and sites preventative maintenance. PB undertook a separate analysis of Ergon Energy's vegetation management and access corridors and sites preventative maintenance (section J.3.5).

With respect to non vegetation preventative maintenance, PB noted that Ergon Energy proposed to spend $474 million ($2009–10) in the next regulatory control period. This represented an average (real) increase of 47 per cent compared to the current regulatory control period. PB considered this to be 'a considerable increase'.[2134]

Table J.4 shows PB's breakdown of Ergon Energy's proposed spending on non vegetation preventative maintenance over the next regulatory control period.

[2131] The NARMCOS data model details opex forecasts for preventative maintenance activities for the period 2006/07 to 2014/15. (Ergon Energy, email 3 August 2009, AER-PB Q.VP.5 & VP.48 confidential; Ergon Energy, *Regulatory proposal*, July 2009, p. 268.)

[2132] Ergon Energy, *Regulatory proposal*, July 2009, p. 268.

[2133] Ergon Energy, *Preventative Maintenance Programs for 2010/11–2014/15*, May 2009, p. 12, confidential.

[2134] PB, *Report – Ergon Energy*, October 2009, pp. 122 and 145.

Table J.4: PB breakdown of Ergon Energy's proposed preventative maintenance opex – excluding vegetation and access tracks ($m, $2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Preventative maintenance – excluding vegetation and access tracks	85.0	95.3	95.1	98.4	100.4	474.2

Source: PB, *Report – Ergon Energy*, October 2009, table 6.18, p. 121.

PB observed that Ergon Energy's asset maintenance and management practices were in a transitional stage. It noted Ergon Energy's forecasting approach is moving from a lagging indicator and fixed time based inspection approach to a more condition based knowledge, informed through leading indicators, reflecting an increase in strategic preventative maintenance requirements.[2135]

PB reviewed Ergon Energy's inspection and maintenance programs for each asset class, changes to those programs, and the cost impact of the changes. PB noted that the inspection and maintenance programs were based on qualified risk assessments for each of the asset classes and concluded the programs were reasonable and pragmatic, balancing costs against safety and compliance requirements.[2136] However, PB noted two exceptions to its general conclusion regarding pole assets and visual inspections.

Ground based (pole asset) inspections

PB noted Ergon Energy should have a comprehensive understanding of its pole assets by 2010, and that these assets demonstrate excellent reliability performance. On this basis PB considered the inspection cycle should be increased to 4.5 years, rather than 4 years.[2137] Accordingly, PB recommended reducing the preventative maintenance opex forecast by $15 million, to reflect a longer inspection cycle for poles.[2138]

Inspection of overhead services (visual and full inspections)

PB also considered that the number of visual inspections of customer services could be reduced as a significant increase in full inspections for customer overhead services has been implemented by Ergon Energy. PB stated it considered the increased full inspection program should lead to a reduction in coincident visual inspections, as these tasks achieve similar outcomes. Accordingly, PB recommended a reduction in preventative maintenance opex of $2.9 million ($2009–10).[2139]

Reduction in growth rate of preventative maintenance activities

PB recommended a reduction in Ergon Energy's growth capex proposal for the next regulatory control period and noted this should lead to a decrease in forecast preventative maintenance activities (as network growth is a driver of preventative

[2135] PB, *Report – Ergon Energy*, October 2009, p. 144.
[2136] PB, *Report – Ergon Energy*, October 2009, p. 123.
[2137] PB, *Report – Ergon Energy*, October 2009, pp. 123–124.
[2138] PB, *Report – Ergon Energy*, October 2009, p. 124.
[2139] PB, *Report – Ergon Energy*, October 2009, p. 124.

maintenance). PB estimated a consequential reduction in preventative maintenance opex of $14 million in the next regulatory control period.[2140]

PB's recommended reductions to Ergon Energy's preventative maintenance opex total around $33 million ($2009–10) in the next regulatory control period.[2141]

AER considerations

The AER's consideration of vegetation management and access tracks preventative maintenance opex is considered in section J.3.5 of this draft decision. This section covers the remaining components of Ergon Energy's preventative maintenance opex.

The AER notes Ergon Energy has forecast its preventative maintenance opex using a bottom up methodology that relies on its asset maintenance strategy, and the preventative maintenance programs developed for the next regulatory control period. The strategy and programs are integrated with other policies and the detailed asset equipment plans that underpin Ergon Energy's individual asset management.

The information on programs and policies is used in the NARMCOS model to calculate required work units, work unit costs, and aggregate preventative maintenance opex across Ergon Energy's 26 asset classes.

The AER considers that Ergon Energy's bottom up approach to developing preventative maintenance forecasts is an appropriate model that takes into account the risk analysis, cost data and policies that need to be incorporated into its opex forecasts.

The AER notes there are a number of program changes driving increases in preventative maintenance. Of these programs PB concluded that all but two programs (ground based inspections and full inspection of overheads) were based on reasonable and pragmatic inspection cycles resulting in prudent and efficient programs.[2142]

Ground based (pole asset) inspections

The ground based inspection program is primarily focussed on wooden poles. Ergon Energy's asset equipment plan for wooden poles revealed an inspection cycle that increased from every 3 years to every 4 years in 2006. The AER notes that poles account for over 40 per cent of Ergon Energy's preventative maintenance opex. The AER also notes PB's assessment of the excellent reliability of these assets in the current regulatory control period.

Ergon Energy has based its proposed 4 year inspection cycle on the requirements of the Electrical Safety Office Code of Practice, which requires 5 year inspection cycles or longer cycles based on risk driven engineering assessment.[2143]

The AER considers that Ergon Energy has been overly conservative in its approach to risk regarding the possible failure of its wooden poles. The AER considers that given

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2140 PB, *Report – Ergon Energy*, October 2009, pp. 113 and 146–147.
2141 Ergon Energy, *Regulatory proposal*, July 2009, pp. 113 and 124.
2142 PB, *Report – Ergon Energy*, October 2009, pp. 123–124.
2143 PB, *Report – Ergon Energy*, October 2009, p. 123.

the current reliability of the poles, and Ergon Energy's comprehensive knowledge of the assets arising from the previous inspection cycle, increasing the inspection cycle to 4.5 years will result in opex forecasts that better reflect the costs of a prudent operator. The AER notes PB estimated the opex saving arising from this change to be around $15 million ($2009–10) in the next regulatory control period.

The AER requested Ergon Energy to revise its modelling and incorporate the longer inspection cycle in its preventative maintenance forecast.[2144]

Inspection of overhead services (visual and full inspections)

The inspection program for overhead services has been developed in response to identification of a large number of distribution services that are not installed in accordance with current standards creating a risk of personal injury or death. Ergon Energy introduced a significant increase in full inspections for customer overhead distribution services, and is maintaining that increase throughout the next regulatory control period.[2145]

The AER considers such a preventative maintenance program is appropriate but notes PB has identified an overlap in the program with a similar program: coincident visual inspections. As the two programs achieve similar outcomes, the AER considers Ergon Energy should take into account a reduction in the number of coincident visual inspections, to offset the increase in full inspections, after the pilot program is completed in 2009–10. The AER notes PB estimated the opex saving arising from this change to be of the order of $2.8 million in the next regulatory control period.

The AER requested Ergon Energy to revise its modelling to offset the increase in full inspections against coincident visual inspection in its preventative maintenance forecast.[2146]

Reduction in growth rate of preventative maintenance activities

The AER has also considered the impact of a reduction in the growth capex program, and notes that such a reduction should have the effect of decreasing the preventative maintenance program and opex forecast. The AER notes PB assessed this reduction to be in the order of $14 million in the next regulatory control period.[2147]

The AER requested Ergon Energy to revise its modelling to base its preventative maintenance forecast on the revised growth capex forecast.[2148]

QCA 2004 draft determination[2149]

The AER notes that during the current regulatory control period, Ergon Energy requested and the QCA granted a significant amount of expenditure allowance for an intensive asset inspection regime. The purpose of this program was to change the focus of its maintenance program from being reactive to preventative. Ergon Energy submitted that its new asset management regimes implemented during the current

2144 AER, modelling request, 6 November 2009.
2145 Ergon Energy, *Regulatory proposal*, July 2009, pp. 28 and 31 (as shown in table 7).
2146 AER, modelling request, 6 November 2009.
2147 PB, *Report – Ergon Energy*, October 2009, pp. 113 and 146–147.
2148 AER, modelling request, 6 November 2009.
2149 QCA, *Draft Determination Regulation of Electricity Distribution*, December 2004.

regulatory control period would provide the foundation for improved efficiencies in future.[2150]

The AER observes that Ergon Energy has not incorporated savings in its regulatory proposal to account for efficiency gains from the new asset management systems activities occurring during the current regulatory control period.

The AER sought further information from Ergon Energy on this matter. In response to an AER request for information, Ergon Energy advised that benefits have just begun to be realised as a result of work done during the current regulatory control period, which involved rolling out the Ellipse IT database system.[2151] Ergon Energy stated that efficiency savings would be captured in the form of the proposed 3 per cent annual productivity saving and the lower unit rates and contractor costs that were calculated.[2152]

The AER notes that Ergon Energy has factored productivity improvements into its opex forecast. The AER considers that these productivity savings can be considered to include expected efficiency gains arising from the implementation of the new asset management regimes.[2153]

Revised forecast

Ergon Energy advised that the adjustment associated with preventative maintenance activities (excluding vegetation and access tracks costs and input cost escalation) results in a reduction of $32 million ($2009–10) to the forecast controllable opex for the next regulatory control period. This amount represents the following adjustments:

- $17 million to account for the longer inspection cycles for ground based poles
- $8.7 million as a result of growth capex programs being reduced
- $1.7 million reduction in coincident visual inspection program
- $5.0 million to account for the capex/opex trade off (see discussion in section J.3.1).

AER conclusion

For the reasons discussed, as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is not satisfied that Ergon Energy's forecast preventative maintenance opex (excluding vegetation) reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed preventative maintenance opex by $33 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary

[2150] Ergon Energy statement as quoted in *QCA 2004 draft decision*, p. 131.
[2151] Ellipse is an IT information system used by Ergon Energy to manage assets, works finance and logistics. (Ergon Energy, Regulatory proposal, July 2009, p. 50. Ellipse was introduced in 2006–07 however benefits of this system could not be realised until later.)
[2152] Ergon Energy, AER.ERG.27.03, 22 October 2009, confidential.

for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

J.3.4.2 Corrective maintenance

Ergon Energy's corrective maintenance opex relates to planned repair and replacement work that is carried out after defects are identified, in order to fix the defect. Corrective maintenance also includes repair or replacement works to restore supply following an outage. Ergon Energy stated it carries out corrective maintenance work regularly and at planned intervals.[2154]

Regulatory proposal

Ergon Energy proposed to spend $590 million on corrective maintenance activities over the next regulatory control period. Table J.5 shows Ergon Energy's proposed corrective maintenance expenditure for the next regulatory control period.

Ergon Energy stated that 73 per cent ($160 million) of its proposed corrective maintenance forecast relates to vegetation and access track remediation activities that are required to comply with electrical safety and environmental legislation. This is discussed in section J.3.5 of this draft decision. The remaining 29 per cent of corrective maintenance opex relates to corrective works conducted on network assets in order to minimise condition–based and age–related defects.[2155] Ergon Energy stated that the defects would be identified when carrying out its proposed preventative maintenance activities.[2156]

Ergon Energy noted that its corrective maintenance forecasts are based on actual 2007–08 costs. No abnormal items were identified in the 2007–08 data.[2157] Scope changes were added to the base year. Base year costs were then escalated using real growth escalators.

Ergon Energy stated that 2007–08 was chosen as the base year as it reflected the impact of the Ellipse IT system on corrective maintenance opex.[2158]

Scope changes for a number of additional items (which did not occur in the 2007–08 base year) have been added to develop the forecast for the next regulatory control period. These items were an estimate of the additional reactive corrective maintenance that was likely to occur during 2008–09 for which costs had not previously been incurred. The additional items relate to:[2159]

- repair issues identified following incidents and investigations
- dismantling of old lines which have been replaced
- asbestos cleanup in ground mounted and chamber substations
- increasing failure rates of meters.

[2154] Ergon Energy, *Regulatory proposal*, July 2009, p. 272.
[2155] Ergon Energy, *Regulatory proposal*, July 2009, p. 272.
[2156] Ergon Energy, *Regulatory proposal*, July 2009, p. 272.
[2157] Ergon Energy, *Regulatory proposal*, July 2009, pp. 273–274.
[2158] Ergon Energy, *Regulatory proposal*, July 2009, p. 274.
[2159] Ergon Energy, *Regulatory proposal*, July 2009, p. 274.

Ergon Energy noted corrective maintenance conducted in response to preventative maintenance activities is a reactive cost and cannot be planned in advance.[2160] Ergon Energy submitted that the increased inspection program to be undertaken as part of the preventative maintenance program would identify the need for more corrective maintenance work to be undertaken.[2161]

Table J.5: Ergon Energy proposed corrective maintenance opex ($m, 2009–10)

	2010–11	2011–12	2011–12	2011–12	2011–12	Total
Corrective maintenance	121.9	121.5	122.8	117.9	105.7	589.8

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 71, p. 272.

Consultant review

This section refers to PB's review of corrective maintenance associated with planned repair work in response to defects that have been identified as part of preventative maintenance. Vegetation management, access corridors and sites corrective maintenance was considered separately by PB and has been reviewed in section J.3.5 of this appendix.

PB noted that Ergon Energy proposed to spend $160 million on (excluding vegetation and access tracks costs) corrective maintenance in the next regulatory control period. Table J.6 shows PB's breakdown of Ergon Energy's proposed spending on corrective maintenance (excluding vegetation and access tracks costs) for the next regulatory control period.

Table J.6: PB breakdown of Ergon Energy's proposed corrective maintenance opex – excluding vegetation and access tracks ($m, $2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Corrective maintenance — excluding vegetation and access tracks	31.5	31.5	32.1	32.4	32.3	159.8

Source: PB, *Report – Ergon Energy*, October 2009, table 6.22, p. 125.

PB reviewed Ergon Energy's forecast methodology and proposed scope changes. PB reviewed the four scope changes proposed by Ergon Energy. PB found the proposed scope changes as reasonable and justified with the exception of one.[2162]

PB did not consider the scope change concerning the dismantling of old lines that have been replaced was correctly addressed.[2163] PB stated that this program reflected capital works, and considered this cost would be capitalised as part of project costs,[2164] therefore including this cost would result in a double count of the

2160 Ergon Energy, *Regulatory proposal*, July 2009, p. 273.
2161 Ergon Energy, *Regulatory proposal*, July 2009, p. 29.
2162 PB, *Report – Ergon Energy*, October 2009, p. 126.
2163 PB, *Report – Ergon Energy*, October 2009, p. 126.
2164 PB, *Report – Ergon Energy*, October 2009, p. 126.

expenditures. PB recommended that a $9.4 million (or 1.6 per cent) reduction should be made to the opex forecast relating to this expenditure.[2165]

AER considerations

The AER's consideration of vegetation management and access tracks corrective maintenance opex is considered in section J.3.5 of this draft decision. This section covers the remaining components of Ergon Energy's corrective maintenance opex.

The AER reviewed Ergon Energy's corrective maintenance opex forecasts and the methodology used to derive them. For corrective maintenance a baseline/scope change forecasting methodology has been used to forecast opex in the next regulatory control period.

The AER considers the use of 2007–08 base year data is appropriate as this data incorporates the impact of the Ellipse program on corrective maintenance works.[2166] The AER considers estimates drawn from the Ellipse data management program are more accurate than the prior year's data, which was based on manual records.

The AER notes that at this stage, the amount of corrective maintenance works conducted by Ergon Energy is positively proportional to increased inspection timings. The AER considers that network maintenance works should be based on the condition status of the asset, rather than the number of inspections carried out. The AER considers that a prudent and efficient DNSP would consider the condition of network assets as the main driver of corrective maintenance activities.

Given that Ergon Energy is a relatively new organisation and at present does not have the systems and knowledge to undertake condition based modelling of its maintenance program, the AER accepts the forecasting methodology proposed by Ergon Energy. The AER notes that Ergon Energy's proposed increasing its preventative maintenance program may, in turn increase its corrective maintenance activities in the next regulatory control period.

The AER notes that Ergon Energy's new asset management regime is committed to supporting early detection and management of likely asset failures. Therefore, it is reasonable to expect the improvements in the preventative maintenance programs will reduce the amount of corrective maintenance in the medium to long term. The AER will reassess Ergon Energy's proposed forecasting methodology at the next regulatory reset process to ensure that reductions in corrective maintenance are being achieved.

The AER has reviewed the information provided by Ergon Energy and PB regarding scope changes that impact on the volume of corrective maintenance work. The AER considers that the adjustments to the base year opex for repair issues identified following incidents and investigations are appropriate. Furthermore, the AER considers that the adjustments to the base year opex for asbestos cleanup in ground mounted and chamber substations, and increasing failure rates of meters are appropriate.

[2165] PB, *Report – Ergon Energy*, October 2009, p. 127.
[2166] The Ellipse program was introduced in 2006–07.

However, the AER notes PB's advice that there has been a double count of costs in relation to the removal of old lines. The AER does not consider it appropriate to amend base year opex for this scope change, on the basis that these costs are included in Ergon Energy's capex project costs. The AER requested Ergon Energy to amend its model to remove the proposed scope change from the base year for corrective maintenance.[2167]

Ergon Energy advised that eliminating the scope change concerning the removal of old poles and incorporating an adjustment for capex/opex trade off results in a reduction of $14.4 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[2168]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is not satisfied that Ergon Energy's proposed non vegetation corrective maintenance opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed corrective maintenance opex by $14.4 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

J.3.4.3 Forced maintenance

Ergon Energy's forced maintenance costs relate to unplanned repair, replacement or restoration work conducted on damaged assets caused by an unexpected event or failure, such as severe weather.[2169]

Regulatory proposal

Ergon Energy stated that the volume and costs associated with forced maintenance activities cannot be accurately forecast due to the reactive nature of such maintenance activities. Instead, an annual provision is made using a hybrid bottom up and baseline/scope change approach.[2170]

Ergon Energy clarified how it derived its base year subsequent to publishing its regulatory proposal. In correspondence to the AER, Ergon Energy confirmed that it looked at the average of three years (2006–07, 2007–08 and 2008–09) in order to adjust the base year of 2007–08 down by 7 per cent to remove costs in 2007–08 that were abnormal. No scope changes were added to the base year. Ergon Energy stated the revised amount reflects historical expenditure trends.[2171] [2172] Ergon Energy then

[2167] AER, AER, modelling request, 6 November 2009.
[2168] Ergon Energy, Response to AER modelling request PL869c, 13 November 2009 confidential.
[2169] Ergon Energy, *Regulatory proposal*, July 2009, p. 276; and Ergon Energy, *Qld Public forum presentation slides,* 3 August 2009.
[2170] Ergon Energy, *Regulatory proposal*, July 2009, p. 276.
[2171] Ergon Energy, AER.ERG.27.06, 20 October 2009 confidential.
[2172] Ergon Energy, AER–PB Q.VP.79, 24 August 2009 confidential.

used SKM input cost escalators to forecast the forced maintenance opex in the next regulatory control period.[2173]

Ergon Energy submitted that this it is the most accurate way of forecasting this kind of expenditure given that Ergon Energy has an extensive asset base that spans a wide geographic area with diverse weather types and patterns.[2174] Ergon Energy forecasts its forced maintenance opex to remain flat throughout the next regulatory control period.[2175]

Ergon Energy's NARMCOS model was used to derive the expenditure forecast for forced maintenance activities by asset class.[2176] The adjusted 2007–08 forced maintenance base year expenditure was split in the NARMCOS model between the 26 asset classes based on known historical trends, expected failure rates on the basis of subject matter expertise.[2177]

Table J.7 shows Ergon Energy's proposed forced maintenance expenditure for the next regulatory control period.

Table J.7: Ergon Energy's proposed forced maintenance opex ($m, 2009–10)

	2010–11	2011–12	2011–12	2011–12	2011–12	Total
Forced maintenance	41.0	40.9	41.3	41.4	41.1	205.7

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 72, p. 275.

Consultant review

PB noted that Ergon Energy proposed to spend $206 million on forced maintenance in the next regulatory control period, an average (real) decrease of 2 per cent compared with the current regulatory control period.[2178]

PB found that there was no growth anticipated in the forced maintenance cost category over the next regulatory control period and considered the forecasting approach suitable.[2179]

PB reviewed Ergon Energy's *2007–08 Annual Network Reliability Report* that shows a percentage break down of network faults and causes of the failure rates.[2180] PB found that 40 per cent of all incidents are related to plant condition and performance. Using this rate, PB advised that 40 per cent should be used as an indicator of the proportion of forced maintenance costs to be reduced as a result of improvements

2173 Ergon Energy, *Regulatory proposal*, July 2009, p. 337.
2174 Ergon Energy, *Regulatory proposal*, July 2009, p. 277.
2175 Ergon Energy, *Regulatory proposal*, July 2009, p. 276.
2176 Ergon Energy, *Regulatory proposal*, July 2009, p. 277.
2177 Ergon Energy, *Regulatory proposal*, July 2009, pp. 276–277.
2178 PB, *Report – Ergon Energy*, October 2009, p. 145.
2179 PB, *Report – Ergon Energy*, October 2009, p. 128.
2180 PB, *Report – Ergon Energy*, October 2009, p. 128.

generated by the asset replacement capex and increased maintenance activities proposed by Ergon Energy.[2181]

PB considered that Ergon Energy's proposed asset replacement and corrective maintenance expenditure programs, if approved and then implemented, should reduce the need for forced maintenance expenditure.[2182]

PB recommended a reduction in forced maintenance opex of $6.7 million in the next regulatory control period to account for these efficiencies.[2183]

AER considerations

The AER has reviewed Ergon Energy's proposed forced maintenance opex and the methodology used to derive it. The AER considers 2007–08 is an appropriate base year and notes the adjustment made by Ergon Energy to make the expenditures align with historical trends.

However, the AER has concerns regarding the interaction between forced maintenance and corrective and preventative maintenance activities. As noted by PB, Ergon Energy has not explicitly accounted for the likely improvement in network assets as a result of increased spending in other network maintenance activities. This is relevant as not all forced maintenance will be required as a result of storms or accidents. Some forced maintenance is necessary where assets fail due to poor condition. The AER considers that Ergon Energy's corrective and preventative maintenance programs, and replacement capex program should all contribute to a reduction in forced maintenance due to poor condition or performance of assets.

The AER notes that Ergon Energy has not included any savings to forced maintenance activities over the next regulatory control period to offset its proposed:

- increased spending on replacement capex projects;
- increased spending on preventative and corrective maintenance activities.

The AER notes PB's review of Ergon Energy's forced maintenance activities found that 40 per cent of forced maintenance faults arose from poor plant condition or performance. PB recommended using the 40 per cent rate as an indicator of the proportion of forced maintenance that is likely to be improved by increases in asset replacement capex and preventative maintenance activities proposed by Ergon Energy. PB estimated this to result in a $6.7 million reduction to forced maintenance opex.

The AER considers the proposed forecast forced maintenance opex should incorporate the likely reduction in costs as a result of increased spending in replacement capex and increased preventative and corrective maintenance activities. Ergon Energy was required to amend its modelling to reflect the impact of increases

[2181] PB, *Report – Ergon Energy*, October 2009, p. 129.
[2182] PB, *Report – Ergon Energy*, October 2009, pp. 128–129.
[2183] PB, *Report – Ergon Energy*, October 2009, p. 130.

in asset replacement capex and preventative maintenance activities on forced maintenance opex forecasts.

Ergon Energy advised that the adjustments associated with forced maintenance activities results in a reduction of $6.7 million ($2009–10) to the forecast controllable opex for the next regulatory control period.

AER conclusion

For the reasons discussed, as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is not satisfied that Ergon Energy's forecast forced maintenance opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed forced maintenance expenditure by $6.7 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

J.3.5 Vegetation management, access tracks and sites

Ergon Energy's vegetation preventative management activities include identifying how much vegetation cutting is required and the likely number of crews needed to do the work. Its preventative maintenance activities associated with its access tracks and sites program relates to routine inspection programs associated with powerlines, enclosed substations and pad-mount stations.[2184] Ergon Energy stated that its preventative maintenance activities are carried out at predetermined intervals, or in accordance with prescribed criteria.[2185]

Ergon Energy's vegetation corrective maintenance is carried out in response to defects identified from undertaking preventative maintenance activities. Ergon Energy stated that increased corrective maintenance activities would result from the proposed increase in preventative maintenance activities.[2186]

Regulatory proposal

Ergon Energy forecast its proposed preventative and corrective maintenance costs in relation to vegetation and access track work over the next regulatory control period using a bottom up approach.[2187] Ergon Energy engaged VEMCO, a specialist vegetation management company, to assist with determining the work volume and cost estimates of the vegetation and access work.[2188]

The estimated volume of vegetation and access tracks and sites work was based on a sampling condition assessment undertaken by VEMCO. The costs of vegetation works were based on an average of the VEMCO derived unit rate costs and the higher

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[2184] Ergon Energy, *Preventative Maintenance Programs for 2010–11 to 2014–15*, May 2009 confidential, p. 7.
[2185] Ergon Energy, *Regulatory proposal*, July 2009, p. 267.
[2186] Ergon Energy, *Regulatory proposal*, July 2009, p. 274.
[2187] Ergon Energy, *Regulatory proposal*, July 2009, pp. 267–268 and 273.
[2188] Ergon Energy, *Regulatory proposal*, July 2009, p. 268.

historical actual unit rates that Ergon Energy paid to contractors in the current regulatory control period.[2189]

Ergon Energy stated that an increased opex allowance for vegetation and access track and sites management activities was needed to clear a rural backlog and to comply with regulatory obligations. Furthermore, it submitted that additional funding was needed to upgrade the vegetation management program based on Ergon Energy's *Vegetation Strategy*.[2190]

Ergon Energy stated that the main contributing factor to the rural backlog was an underestimation of vegetation maintenance costs during the current regulatory control period.[2191] Ergon Energy said that a review of its *Vegetation Strategy* identified areas of misalignment between the outcomes of its vegetation program compared to the original strategy intent. Subsequently, 50 per cent of the rural network was not cleared during the current regulatory control period and a high number of trees remain in contact with conductors. It noted the backlog of work is in breach of legislative requirements.[2192]

During the current regulatory control period, Ergon Energy implemented a new vegetation management strategy to deal with its backlog issue.[2193] Ergon Energy changed from a strategy of managing urban vegetation annually and rural vegetation on a three yearly cycle to a bio–diversity model approach that incorporates variations in climate and vegetation. Ergon Energy advised that its new biodiversity model enables specific risk profiling and prioritisation of individual feeders for each of its thirteen bioregions to optimise vegetation inspection and cutting cycles. Ergon Energy stated implementation of the biodiversity model to clear backlog work would achieve legislative compliance in a faster timeframe than would otherwise be the case.[2194]

Ergon Energy forecast increased opex for access track works to continue its access track program which was introduced in the current regulatory control period. This program also seeks to comply with the *Aboriginal Cultural Heritage Act 2003*, the *Nature Conservation Act* and to install standard signage on access tracks.[2195]

Ergon Energy stated that its preventative maintenance opex forecast concerning vegetation management activities reflects its corporate policy outlined in the documents *Preventative Maintenance Programs for 2010/11 –2014/15* and *Code of Practice Powerline Clearance (Vegetation) 2006*.[2196] Ergon Energy stated that its proposed corrective expenditure forecast is estimated in accordance with business policies and processes outlined in Ergon Energy's *Practice Powerline Clearance*

[2189] Ergon Energy, *Regulatory proposa*l, July 2009, p. 268.
[2190] Ergon Energy, *Regulatory proposa*l, July 2009, p. 268.
[2191] Ergon Energy, AER-PB Q.VP.8 and VP.51, 3 August 2009 confidential.
[2192] Ergon Energy, *Vegetation Strategy*, p.8 confidential.
[2193] Ergon Energy's new vegetation management strategy was implemented in July 2009.
[2194] Ergon Energy, PB.ERG.VP68, 26 August 2009 confidential.
[2195] Ergon Energy, *Regulatory proposal*, July 2009, p. 270.
[2196] Ergon Energy, *Regulatory proposal*, July 2009, pp. 273–274.

(Vegetation) 2006, Ten and Five Year Maintenance Works Plan and *Annual Works Plan.*[2197]

Consultant review

PB conducted a detailed review of Ergon Energy's proposed vegetation management and access tracks and sites opex for the next regulatory control period.

PB noted that Ergon Energy proposed an opex allowance of $549 million (or 29 per cent of total controllable opex) to cover its vegetation management, access corridors and sites programs in the next regulatory control period. Table J.8 shows PB's breakdown of Ergon Energy's proposed spending on preventative and corrective maintenance (including vegetation and access tracks costs) over the next regulatory control period.

Table J.8: PB breakdown of Ergon Energy's proposed vegetation and access tracks and sites opex ($m, $2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Preventative – vegetation	17.3	17.7	18.4	18.2	16.9	88.5
Preventative – tracks and sites	6.5	6.6	6.6	6.7	4.4	30.8
Corrective – vegetation	78.1	77.5	78.0	72.6	60.2	366.4
Corrective – tracks and sites	12.2	12.5	12.7	12.9	13.1	63.4
Total	114.1	114.3	115.7	110.4	94.6	549.1

Source: PB, *Report – Ergon Energy*, October 2009, table 6.27, p. 131.

PB reviewed Ergon Energy's forecast vegetation and access tracks and sites opex by assessing the spending proposal against Ergon Energy's *Vegetation Strategy*, the *Code of Practice: Powerline Clearance (Vegetation) 2006,*[2198] and information received from in response to questions. PB noted that Ergon Energy's forecast spending was aligned with its corporate policy and processes.

PB stated that Ergon Energy provided clear evidence of the need to clear rural backlog work and the need to comply with clearance regulatory standards.[2199] PB also stated that Ergon Energy provided clear evidence of the need for a significant change in its approach to vegetation management. It was generally satisfied that Ergon Energy's proactive biodiversity based strategy was likely to provide a long term efficient framework for vegetation management.[2200]

[2197] Ergon Energy, *Regulatory proposal*, July 2009, p. 274.
[2198] PB, *Report – Ergon Energy*, October 2009, p. 131.
[2199] PB, *Report – Ergon Energy*, October 2009, p. 146.
[2200] PB, *Report – Ergon Energy*, October 2009, p. 132.

PB noted that under Ergon Energy's proposed strategy, the backlog would be cleared in accordance with legislative compliance by mid to late 2012. However, a fully sustainable vegetation position will not be reached until mid to late 2017.[2201]

PB found Ergon Energy's proposed vegetation management opex to be prudent and efficient, with the exception of the following items:[2202]

- Ergon Energy's predictive costing models based on historical costs, included a five per cent cost increase. Ergon Energy did not justify this increase, therefore PB recommended its removal. The impact of removing this cost was estimated to be $12 million in the next regulatory control period.

- Ergon Energy had not incorporated economies of scale within its modelling under the new biodiversity model approach.

- Ergon Energy is required to comply with regulations in relation to the management of endangered species, declared plants and cultural heritage. Costs associated with regulatory compliance fall under Ergon Energy's preventative vegetation allowance. PB noted that while the need for each of these activities is specified, Ergon Energy did not explain the need for a cumulative growth factor applied to the base year for each of these activities. In the absence of any detailed justification, PB recommended a reduction of $4.6 million to remove the activity growth included in these three opex forecasts.

- Ergon Energy's proactive risk management approach towards vegetation management should reduce the inspection cycle times of preventative maintenance activities and generate fewer defects in assets. However, there was no reduction in preventative or corrective maintenance costs to account for this. Data captured during the new inspection program should provide sufficient information for Ergon Energy to prioritise its remediation works throughout the next regulatory control period. PB recommended a reduction of $24 million in vegetation management and access tracks works to account for the flow–on benefits gained as a result of increased spending in other areas of opex activities. PB considered this reduction would account for economies of scale which would be achieved under Ergon Energy's new biodiversity approach.

- Ergon proposed a significant opex increase on the installation of new keys and locks on its access track gates for security reasons. However, as Ergon Energy did not provide a risk assessment or an economic assessment to justify its proposal PB recommended reducing the number of new keys and locks for access gates. This resulted in a reduction of $8.3 million in opex.

As a result of the identified issues, PB recommended a total reduction of $48 million in relation to Ergon Energy's proposed vegetation management and access tracks and sites expenditures.[2203]

2201 Ergon Energy, AER-PB Q.VP.68, 26 August 2009 confidential.
2202 PB, *Report – Ergon Energy*, October 2009, pp. 133–135.
2203 PB, *Report – Ergon Energy*, October 2009, p. 134.

AER considerations

The AER notes that Ergon Energy underestimated the amount and unit costs of vegetation management required during the current regulatory control period and both urban and rural programs fell behind schedule leading to a backlog of work. The backlog of work was independently verified by VEMCO.

The AER considers that the underestimation of work arose because Ergon Energy did not have the systems and processes in place to capture data during the current regulatory control period. Ergon Energy's new vegetation management strategy aims to reduce the incidence and risk of non-compliance with regulatory obligations, and simultaneously address the backlog of work.

The AER accepts that increased vegetation management and access tracks work needs to be carried out in the next regulatory control period.

The AER accepts the methodology used by Ergon Energy to calculate the unit cost rates. It notes that the unit cost rates were based on the average of Ergon Energy's historical unit rates and VEMCO derived rates.

Specifically, the AER is concerned about Ergon Energy's data collection and management processes. Ergon Energy has not had established information systems to record data at an appropriate level of accuracy since it was formed in 1999. For example, it is noted that data entered into Ergon Energy's information management database is subject to delays in entry and is not periodically updated. The lack of established data management systems has led to incomplete data being recorded since Ergon Energy's formation.[2204]

The AER considers that inaccurate data recorded at the start of the information cycle directly affects the accuracy of subsequent calculations and the accuracy of reports generated from this data capture process. However, the AER also considers that the biodiversity model will provide better quality and accurate estimates of vegetation clearing requirements as the new vegetation strategy is progressively executed. The AER considers that with the Ellipse model established and Ergon Energy implementing its biodiversity model, Ergon Energy should be in a position to improve its data capture processes in the remaining years of the current regulatory control period and through out the next regulatory control period.

PB identified a 5 per cent increase that could not be matched against Ergon Energy's historical records. The AER has not been able to ascertain the drivers underlying the cost increase in the next regulatory control period and hence considers that the opex forecast should be re-estimated without this cost increase.

The AER considers that compliance with regulatory requirements in relation to the management of endangered species, declared plants and cultural heritage is an important driver of Ergon Energy's preventative vegetation and access tracks and sites maintenance opex. However the modelling of these components includes a cumulative growth factor. The AER has not been able to ascertain the underlying

[2204] Ergon Energy, *Asset Maintenance Strategy*, p. 16, confidential; *Vegetation Strategy*, p. 11, confidential.

rationale for the application of the cumulative growth factor and hence considers that the opex forecast should be re-estimated without this growth factor being applied.

The AER notes that Ergon Energy has forecast a significant increase in corrective vegetation management, expected to arise directly as a result of the increased inspection regime under the preventative vegetation management program. However, the AER would expect that the increase in corrective maintenance would be alleviated during the course of the next regulatory control period, as inspection cycles identify fewer defects. This expectation of reduced corrective maintenance was noted by Ergon Energy, but its forecasts do not explicitly take this into account.[2205]

In considering this issue, PB recommended reducing the increase in corrective maintenance work volume to 30 per cent in 2009–10 (instead of 100 per cent as modelled by Ergon Energy). The AER has not been able to ascertain how the expected reductions in corrective vegetation maintenance have been incorporated into Ergon Energy's modelling and hence considers that the opex forecast should be re–estimated replacing the 100 per cent increase in work volume with a 30 per cent increase in work volume in 2009–10.

With respect to the installation of new signage and locks on access tracks, the AER notes PB's opinion that the proposed work has not been justified in terms of a risk assessment or economic assessment. In particular, PB found that the proposal to install 300 000 locks with new keys (approximately 3 locks per track kilometre) had not been justified. The AER has not been able to ascertain the economic justification for Ergon Energy's preventative maintenance forecast with regard to access track security. The AER has also not been provided with any information on the risk assessment underpinning the proposed work program. Without such information the AER considers that the opex forecast should be re-estimated using a substitute work program of replacing 24 000 locks and keys (approximately 1 lock per track kilometre).

The AER requested Ergon Energy to remodel its vegetation and access tracks and sites opex forecast to incorporate the following amendments:[2206]

- an unsubstantiated 5 per cent increase excluded from historical unit costs
- removal of cumulative growth factors from opex forecasts in relation to management of endangered species (80 per cent), declared plants (40 per cent) and cultural heritage (100 per cent)
- incorporation of the expected reduction in corrective maintenance by reducing the work volume increase from 100 per cent to 30 per cent
- a reduction in the number of locks and keys to be installed to 24 000.

Ergon Energy advised that the adjustments associated with vegetation and access tracks maintenance activities results in a reduction of $41 million ($2009–10) to the

2205 Ergon Energy, *Regulatory proposal*, July 2009, p. 274.
2206 AER, modelling request, 6 November 2009.

forecast controllable opex for the next regulatory control period. The following adjustments relate to preventative maintenance activities:[2207]

- $4.7 million reduction concerning the removal of the cumulative growth factor in relation to the management of endangered species, declared plants and cultural heritage

- $8.4 million reduction relating to the decrease of number of keys and locks for gates to 24 000 units.

The following adjustments relate to corrective maintenance activities:[2208]

- $27.5 million ($2009–10) step change reduction in the work volume increase in 2009–10 to 30 per cent.

The AER notes that Ergon Energy did not incorporate an adjustment due to the removal of the 5 per cent unit cost increase, due to an error in the modelling request from the AER. The AER has incorporated PB's recommended adjustment of $12 million to corrective maintenance to account for this amendment.

AER conclusion

For the reasons discussed, as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is not satisfied that Ergon Energy's forecast vegetation maintenance opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed vegetation maintenance opex by $53 million ($2009–10) results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

J.3.6 Other operating costs

Other operating costs relate to Ergon Energy's meter reading, customer service activity, training, self insurance, guaranteed service level (GSL) payments, demand management opex and demand management innovation allowance (DMIA) costs.

Regulatory proposal

Ergon Energy proposed to spend $375 million ($ 2009–10) on other opex in the next regulatory control period. Table J.9 shows Ergon Energy's proposed other opex for the next regulatory control period.

[2207] Ergon Energy, Response to AER modelling request PL869c, 13 November 2009 confidential.
[2208] Ergon Energy, Response to AER modelling request PL869c, 13 November 2009 confidential.

Table J.9: Ergon Energy's proposed other operating expenditure ($m, 2009 –10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Meter reading	11.8	11.81	11.8	12.0	12.31	60.4
Customer services	19.8	19.9	19.8	20.2	20.6	101.3
Other operating costs	40.5	41.6	40.5	42.3	43.85	213.7
Total	72.1	73.3	72.0	74.5	76.8	375.3

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 73, p. 278.
Note: Other operating costs includes self insurance costs of $21.5 million. The AER's considerations of self insurance is discussed in chapter 8 of this draft decision.

Meter reading costs include the activities relating to collecting, processing, loading and publishing metering data for market participants in the context of Ergon Energy's NER obligations as a metering data provider for types 5, 6 and 7 metering installations. Ergon Energy noted this opex category specifically excludes metering maintenance work, as this is captured in network maintenance activities.

Customer service costs include customer related activities that are ancillary to the provision of Ergon Energy's broader network connection and metering services, including: cold water reports, check inspections, customer support, managing safety compliance and customer advisory services. Ergon Energy noted this opex category specifically excludes retail and call centre activities, which are treated as overheads.

Ergon Energy stated that other operating costs were estimated using the baseline/scope change approach using 2007–08 as the base year. Abnormalities were removed from the base year and then adjusted for scope changes. Ergon Energy stated that abnormalities included costs associated with full retail competition. This adjusted base year amount was then escalated using forecast growth escalators.[2209]

Ergon Energy proposed the following scope changes be added to its base year opex for other operating costs including: self insurance; debt raising; equity raising; the DMIA; demand management program running costs; GSL payments; and training. Ergon Energy stated that these costs are new items to be added to its opex allowance proposal.

Ergon Energy's proposals regarding self insurance, debt raising and equity raising proposals are discussed in chapter 8 of this draft decision in greater detail.

Customer service and meter reading

Ergon Energy proposed to spend $101 million on customer service activities in the next regulatory control period, an average decrease of 32 per cent (real) compared to the current regulatory control period. In relation to meter reading activities, costs are proposed to increase by 39 per cent (real) to $60 million in the next regulatory control period.

[2209] Ergon Energy, *Regulatory proposal*, July 2009, p. 279.

Ergon Energy forecast its meter reading and customer services opex using 2007–08 opex as a base year. It adjusted for abnormalities and scope changes in relation to NER obligations and full retail contestability impacts, and then escalated costs to reflect future price movements. Ergon Energy's policy on *Customer Care including Meter Reading* was used to inform its expenditure forecasts.[2210]

Ergon Energy noted that its meter reading forecast does not include any allowance for the rollout of smart meters. It noted that any opex costs associated with the requirement to roll out smart meters would be treated as a cost pass through in the next regulatory control period.[2211] Chapter 15 of this draft decision discusses cost pass through in greater detail.

GSL payments
The expenditure estimates cover regulatory obligations associated with the GSL regime under the Queensland Energy Industry Code.

Training
Training costs were previously included as part of the shared cost pool. Due to a change in the International Financial Reporting standards, Ergon Energy amended its accounting treatment whereby training costs of about $20 million per annum will be expensed. Amongst other factors, Ergon Energy stated that they are legally obliged to conduct a large amount of training to ensure that safe work practices are used in the field.[2212]

Demand management
Ergon Energy proposed to spend $61 million in the next regulatory control period in opex relating to its non–network alternative program. Ergon Energy's demand management program consists of a number of broad based programs that provide specific deferral of network augmentation projects identified through the regulatory test process.[2213]

Table J.10 shows a breakdown of Ergon Energy's proposed demand management expenditure.

[2210] Ergon Energy, *Regulatory proposal*, July 2009, p. 279.
[2211] Ergon Energy, *Regulatory proposal*, July 2009, p. 280.
[2212] Ergon Energy, *Regulatory proposal*, July 2009, pp. 29, 281.
[2213] Ergon Energy, *Regulatory proposal*, July 2009, pp. 313–314.

Table J.10: Ergon Energy's proposed demand management opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Demand management—Program management	3.1	3.1	3.1	3.1	3.1	15.5
Large customers	0.6	1.2	1.2	1.2	1.2	5.6
Residential customers	6.2	6.3	6.3	6.4	6.5	31.7
Rural customers	1.1	1.1	1.1	1.1	1.1	5.3
Energy conservation one stop shop	0.7	0.7	0.7	0.7	0.7	3.3
Total						61.2

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 73, p. 278.

Demand management innovation allowance

The $1 million per annum forecast is based on the notional amount provided for Ergon Energy in the AER's framework and approach paper.[2214] Chapter 14 of this draft decision discusses the DMIA in greater detail.

Marketing and sponsorship

The AER sought further information on Ergon Energy proposed forecast marketing and sponsorship costs over the next regulatory control period. Following a request from the AER, Ergon Energy advised that it proposed to spend $2.3 million on marketing and sponsorship costs in the next regulatory control period.[2215]

Ergon Energy stated that its marketing activities involve communicating various safety messages to local communities. An example of this is its "Look up and Live" campaign, which relate to fallen powerlines after storms. Ergon advised spending on sponsorship included providing financial support to a number of entities and events.[2216]

Consultant review

Meter reading and customer service

PB reviewed Ergon Energy's meter reading and customer services expenditure proposal for the next regulatory control period.

PB found that, after removing real escalation, there is no growth or step change in work proposed in the meter reading or customer services cost categories.

However, PB noted that the customer service opex in 2009–10 includes a portion attributable to alternative control services. PB came to this view after assessing Ergon

[2214] AER, *Final framework and approach paper – Energex and Ergon Energy 2010–15 application of schemes*, November 2008.
[2215] Ergon Energy, AER.ERG.29.04, 22 October 2009 confidential.
[2216] Ergon Energy, AER.EE.29.04, 22 October 2009 confidential.

Energy's corporate policy and processes on how to treat costs relating to meter reading and customer services activities. The *Customer Care (including Meter Reading)* document outlines how Ergon Energy classifies its customer care work as either standard control services or alternative control services and forecasts direct costs in accordance with key activities.[2217]

After reviewing these documents, PB found that there was an overlap of key activities of standard and alternative control services in relation to metering and customer care activities. Accordingly, PB recommended a reduction of $80 million during the next regulatory control period resulting from the inclusion of alternative control services activities in the standard control service customer services forecasts.[2218]

Training

PB noted that, although the training costs had now been fully allocated to opex, rather than shared between opex and capex, there had not been an increase in the training costs proposed by Ergon Energy, compared to historical levels.[2219]

Demand management

PB reviewed Ergon Energy's demand management proposal in detail. PB noted that Ergon Energy did not provide any investment approval documents for most of the proposed projects. The two areas where supporting documentation was provided was for its residential broad based program (a preliminary business case was provided) and large customer broad based program (a detailed business case was provided).[2220]

PB found that the various new trials were well targeted and provided a pragmatic approach to increasing awareness and opportunities for demand side activity. However, it noted that there was some lack of preliminary cost–benefit analysis undertaken by Ergon Energy to support its significant increase in demand management related opex.

PB recommended a reduction of $2.5 million in relation to project management costs in the next regulatory control period. It stated that economies of scale and productivity improvements arising from work practices should reduce project management costs over time.[2221]

AER considerations

Meter reading and customer service

The AER reviewed Ergon Energy's forecast of its metering and customer services opex. The AER followed up on PB's concern that that there was a double count of meter reading and customer care costs in its opex forecast. PB stated that this had also been accounted for as part of Ergon Energy's alternative control services costs.[2222]

[2217] PB, *Report – Ergon Energy*, October 2009, p. 136.
[2218] PB, *Report – Ergon Energy*, October 2009, pp. 137–138.
[2219] PB, *Report – Ergon Energy*, October 2009, p. 139.
[2220] PB, *Report – Ergon Energy*, October 2009, pp. 140–141.
[2221] PB, *Report – Ergon Energy*, October 2009, p. 141.
[2222] PB, *Report – Ergon Energy*, October 2009, pp. 137–138.

Ergon Energy was asked to clarify the forecast with reference to source material, but was unable to satisfactorily demonstrate that the opex forecast did not include any alternative control services costs for metering and customer service opex.[2223]

The AER has not been able to verify that alternative control service costs have not been incorporated into Ergon Energy's modelling of standard control services opex. Accordingly, the AER considers that the opex forecast should be amended to remove the alternative control services costs identified by PB. The AER requested Ergon Energy remodel its expenditures to remove these costs and advise the AER of the resultant adjustments, as set out in table J.11.

Other operating costs

GSL payments

The AER has reviewed Ergon Energy's forecast of GSL payments, and the QCA's recent decision on updating the Minimum Service Standards and GSLs.[2224] GSL payments are incurred when the network service provider fails in its duty to provide a reliable service. In essence, GSL payments are a mechanism designed to encourage the network service provider to deliver a reliable and safe service.

The AER considers that GSL payments, under certain circumstances, may be considered regulatory payments in accordance with section 2E of the NEL. For example, in the circumstances where making a GSL payment for breach of a distribution service standard is more efficient than making the necessary investments to ensure compliance with the distribution service standard, the GSL payment appears to satisfy paragraph (b) of section 2E of the NEL. Where a GSL payment is made for a breach of a service standard that occurs due to business mismanagement rather than efficient planning considerations, that payment is less likely to satisfy the NEL definition of a regulatory payment.

The AER accepts that a prudent and efficient network service provider may incur GSL payments in order to meet efficient planning goals and that such payments represent a regulatory obligation imposed on Ergon Energy. As such, the AER considers that it must provide a reasonable opportunity for Ergon Energy to recover the efficient costs of satisfying such obligations under clause 7A(2)(b) of the NEL.

The AER also recognises section 7A(3) of the NEL which indicates that network service providers should be given effective incentives to promote economic efficiency. GSL payments above the efficient level, are costs that the AER considers should be incurred by shareholders rather than customers.

The AER accepts Ergon Energy's forecast of GSL payments as efficient as the forecast is consistent with its historical levels of GSL payments and has been updated (in real terms) where relevant to reflect revised payments schedules.

[2223] Ergon Energy, AER-PB Q.VP94, 9 September 2009 confidential.

[2224] QCA, *Final decision, electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010*, April 2009.

Training

The AER notes that PB review commended Ergon Energy on its approach to utilising its staff on both capex and opex program of works. Efficient work practices utilised by Ergon Energy include: [2225]

- aligned inspections—one ground based visit by a trained asset inspector covers multiple inspections including inspecting poles, pole tops, conductor, vegetation, stays and pole mounted equipment
- bundling of defect work related practices—any defects arising from inspections are combined into work orders and this allows field staff to fix multiple issues on a feeder.

The AER notes it is apparent that Ergon Energy staff need to be trained in multiple areas in order to carry out the diverse opex activities. This is partly because Ergon Energy operates a geographically large and diverse distribution network. The multi–skilling of staff in relation to conducting inspection and maintenance works reduces the travelling time required to complete the works. Further, the AER notes there are a number of regulatory safety requirements requiring staff being trained to carry out work safely.

The AER accepts Ergon Energy’s proposed expenditure forecast on training activities on the basis that PB’s review found that training costs are aligned with historical costs, that no increase is expected to occur in the next regulatory control period and that efficiencies can be achieved by training staff in multiple areas.

Demand management

The AER notes that demand management is at a developmental stage. Currently, Ergon Energy is focusing on collecting verifiable and audited data on its trial projects and determining if this data can be used with its Network Management Plan.

The AER notes that because the demand management projects are still at the preliminary stage of the project life cycle, they cannot be properly costed at this stage. The AER also notes that the purpose of feasibility studies and pilot test activities is to collect information on the demand and supply conditions of the various geographic regions and different customer segments serviced by Ergon Energy. Once this information has been collected and verified, robust cost estimates can then be derived.

The AER has reviewed the proposed demand management program and notes PB’s view that the new demand management trials are well targeted and provide a pragmatic approach to increasing opportunities and awareness of demand management initiatives. However, the AER notes Ergon Energy proposed an additional $2.5 million in opex to cover increased program management costs associated with the new demand management program. Given that the demand management program is an incremental increase and builds on an existing program the AER considers that the increase in program management opex has not been justified by Ergon Energy. The AER also considers that the increase in the demand

[2225] PB, *Report – Ergon Energy*, October 2009, p. 104.

management program should lead to some economies of scale, as the program objectives are enhanced, and co-ordination of initiatives is undertaken.

The AER requested Ergon Energy to remodel its demand management opex forecast to exclude the increased program management costs. [2226]

Marketing and sponsorship
Based on the AER's review of Ergon Energy's proposed marketing costs, the AER is satisfied that the proposed opex relating to marketing costs reasonably reflects the opex criteria, including the opex objectives. The AER considers that advertising and marketing expenditure related to the provision of safe electrical services to the public can also be attributed to standard control services. The AER notes that as part of its legislative compliance, Ergon Energy may be required to embark on advertising campaigns that provide public safety messages. The AER considers that expenditure to satisfy initiatives or comply with legislative obligations such as these are likely to be consistent with the opex objectives, in particular, section 6.5.6(c)(2) of the NER.

However, the AER is not satisfied that sponsorship and other community engagement activities opex reasonably reflects the opex criteria, including the opex objectives. The AER notes that sponsorship and community involvement costs are distinct from the marketing activities identified by Ergon Energy. Sponsorship and community involvement costs are part of the shared cost pool.

The AER notes that Ergon Energy currently provides financial and/or other support to a number of entities and events.[2227] In general, the AER considers that sponsorship activities do not represent expenditure required to comply with the opex objectives. The AER considers that sponsorships are generally designed to increase brand awareness or demonstrate community support. Such activities may provide a benefit to the community but do not relate to the provision of standard control services by DNSPs, nor do they relate to the opex objectives.

The AER considers that Ergon Energy has not demonstrated how its forecast sponsorship proposal is required to achieve the opex objectives, nor has it outlined how it is relevant to the provision of standard control services. The AER requested Ergon Energy to remodel its other operating cost forecast to remove the sponsorship costs.

[2226] AER, modelling request, 6 November 2009.
[2227] Source: http://www.ergon.com.au/community_support/community_sponsorship.asp

Table J.11: AER conclusion on demand management costs and marketing and sponsorship costs ($m, $2009 –10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Removal of the double count of alternative control services and unregulated services (metering service component)	–5.7	–5.8	–5.9	–6.1	–6.3	–29.7
Removal of the double count of alternative control services and unregulated services (metering service component)	–9.6	–9.7	–9.9	–10.2	–10.5	–49.8
Reduction in demand management costs as per PB methodology	–0.5	–0.5	–0.5	–0.5	–0.5	–2.5
Reduction in marketing and sponsorship costs	–0.3	–0.3	–0.3	–0.3	–0.3	–1.5

Source: AER, modelling request, 13 November 2009.
Note: Totals may not add due to rounding.

Ergon Energy advised that the adjustments associated with other operating costs result in a reduction of $84 million ($2009–10) to the forecast controllable opex for the next regulatory control period. This total represents the following adjustments:[2228]

- $30 million to remove the double count of alternative control services and unregulated services (metering service component) costs
- $50 million remove the double count of alternative control services and unregulated services (customer service component) costs
- $2.5 million removal of the incremental increase in project management costs
- $1.5 million reduction removal of sponsorship activity costs.

AER conclusion

For the reasons discussed, as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is not satisfied that Ergon Energy's forecast other opex (excluding self insurance and debt raising) reasonably reflects the opex criteria, including the opex objectives. The AER considers the minimum amendment necessary to the other opex forecast is $84 million. In coming to this view the AER has had regard to the opex factors.

[2228] Ergon Energy, response to AER modelling request PL869c, 13 November 2009, confidential.

J.3.7 Shared costs – ICT systems

Ergon Energy regulatory proposal

The majority of Ergon Energy's total expenditure on information and communications technology (ICT) is delivered under Ergon Energy's arrangement with SPARQ Solutions (SPARQ), for which Ergon Energy is charged service fees. These service fees charged by SPARQ are treated as pooled overheads by Ergon Energy.[2229] The AER notes that Ergon Energy allocates shared costs in accordance with the AER's approved CAM, which results in 77 per cent of shared costs being allocated to capex and 23 per cent being allocated to opex.[2230]

In summary, the services provided by SPARQ to Ergon Energy include:[2231]

- corporate ICT services, including help desk support
- ICT procurement of hardware and software
- voice and data telecommunication
- infrastructure services, including mainframe, corporate data, storage area network, Unix, Windows and email servers
- business application services used in the provision of distribution services.

AER considerations

The AER's detailed considerations of Ergon Energy's proposed ICT overheads are set out in section G.5.5 of this draft decision. Following a request from the AER, Ergon Energy advised that the adjustment associated with opex overhead costs associated with ICT activities result in a reduction of $6.4 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[2232]

Table J.12: AER conclusion on ICT shared costs expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Reduction in expensed ICT shared costs	–0.2.	–0.9	–1.7	–1.8	–1.9	–6.4

Note: Numbers may not add due to rounding.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, submissions, PB's reports and supporting information, the AER is not satisfied that Ergon Energy's shared overheads in relation to ICT activities reasonably reflects the opex criteria, including the opex objectives. The

[2229] Ergon Energy, *Regulatory proposal*, July 2009, p. 227.
[2230] PB, *Report – Ergon Energy*, October 2009, p. 19.
[2231] Ergon Energy, *Regulatory proposal*, July 2009, pp. 344–345.
[2232] Ergon Energy, Response to AER modelling request PL869c, 13 November 2009 confidential.

AER considers the minimum amendment necessary to the other opex forecast is $6.4 million. In coming to this view the AER has had regard to the opex factors.

J.4 AER conclusion

The AER has reviewed Ergon Energy's proposed forecast controllable opex allowance and, for the reasons set out in this appendix, is not satisfied that the proposed forecast opex allowance reasonably reflects the opex criteria under clause 6.5.6(c) of the NER. In reaching this conclusion, the AER has had regard to the opex factors set out in clause 6.5.6(e) of the NER. In particular the AER considers:

- the proposed controllable opex does not reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives

- the proposed controllable opex does not reflect the efficient costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the opex objectives

- the proposed controllable opex, has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the opex criteria.

As the AER is not satisfied that the opex allowance reasonably reflects the opex criteria, under clause 6.5.6(d) of the NER the AER must not accept the forecast opex proposed by Ergon Energy. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the opex for Ergon Energy over the next regulatory control period which it is satisfied reasonably reflects the opex criteria, taking into account the opex factors. Allowing for the adjustments listed above, the AER's estimate of forecast opex for Ergon Energy is $1680 million ($2009–10) (excluding the AER's revisions to input cost escalators), as set out in table J.13.

Table J.13: AER conclusion on Ergon Energy's controllable opex, excluding input escalation ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy's controllable opex[a]	365.9	377.3	381.2	382.3	370.2	1876.9
Adjustment to preventative maintenance	–4.3	–5.5	–6.7	–7.8	–8.6	–32.9
Adjustment to corrective maintenance	–2.2	–2.7	–3.1	–3.3	–3.1	–14.4
Adjustment to forced maintenance	–0.0	–0.4	–1.2	–2.0	–3.0	–6.7
Adjustment to vegetation management	–9.9	–10.5	–11.1	–11.5	–9.6	–52.6
Adjustment to other opex	–16.1	–16.2	–16.5	–17.2	–17.6	–83.6
Adjustment to ICT shared costs	–0.2	–0.9	–1.7	–1.8	–1.9	–6.4
Total adjustments	–32.7	–36.2	–40.3	–43.5	–43.9	–196.6
AER adjusted controllable opex [b]	333.2	341.1	340.9	338.8	326.3	1680.3

Note: Totals may not add due to rounding.

(a) Ergon Energy's controllable opex does not include proposed self insurance costs of $25.1 million or proposed debt and equity raising costs of ($94.1 million).

(b) The AER's adjusted controllable opex does not include the application of the AER's revised input cost escalators. The application of the AER's revised input cost escalators are discussed in chapter 8 of this draft decision.

K. Self insurance

This appendix sets out the AER's assessment of the Qld DNSPs' proposed self insurance allowances in their opex forecasts for the next regulatory control period.

K.1 Qld DNSP regulatory proposals

The Qld DNSPs' proposed allowances for self insurance premiums for the next regulatory control period is shown in table K.1.

Table K.1: Energex and Ergon Energy self insurance costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	2.8	2.9	3.1	3.2	3.0	15.1
Ergon Energy	4.2	4.2	4.3	4.4	4.5	21.5

Source: Energex, *Regulatory proposal*, July 2009, p. 172; Ergon Energy, *Regulatory proposal*, July 2009, p. 305; and Ergon Energy, email response, 18 November 2009, confidential.

Energex engaged Finity Consulting Pty Ltd (Finity) to provide actuarial assessments of its self insurance costs. Ergon Energy engaged Synergies Economic Consulting, in partnership with Finity.[2233]

Energex and Ergon Energy provided board resolutions to self insure in their regulatory proposals.[2234]

Finity identified three risk categories which it considered may form part of the self insurance program for the Qld DNSPs:[2235]

- uninsured storm damage
- below deductible liability claims
- uninsured retailer credit risk (Energex only).

Uninsured amounts are where a DNSP either cannot obtain external insurance or where the DNSP has elected to self insure to lower costs. Deductible amounts represent the amount a DNSP must pay, or retain, if an insurance event occurs, before the DNSP can make a claim on the insurance policy.

To develop estimates of self insurance premiums, Finity used historical loss data from the Qld DNSPs (adjusted for inflation, claims not yet reported and changes in

[2233] Finity, *Review of Self Insurance Program: Energex Limited*, May 2009, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, March 2009, confidential.

[2234] Energex, *Board memorandum 23/02/2009*, confidential; and. Ergon Energy, *Minutes of the board meeting 27/03/2009,* confidential.

[2235] Finity, *Review of Self Insurance Program: Energex*, p. 2, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, p. 2, confidential.

exposure) for public liability claims, while also applying wind speed and damage curves to the Qld DNSPs' attritional data for storm damage.[2236]

K.2 Issues and AER considerations

K.2.1 Self insurance assessment criteria

Self insurance is an alternative risk management method to external insurance, where the network service provider bears the risk of an event that is beyond the network service provider's control. Self insurance may also be necessary if insurance is not available or only available on uneconomic terms or conditions.[2237] It is important to note that self insurance should only be for risks that are not otherwise remunerated through other components of the total revenue building blocks.

The AER notes that self insurance for certain events has been previously considered by the ACCC and AER under the National Electricity Code and the NEL.[2238]

It is generally recognised that there is a difference between self insurance and risk retention. Even if a risk is insurable, a prudent network service provider may not insure against minor risks, meaning that the external insurance policy will stipulate a minimum amount that the claimant must pay if a claim is made. This amount is called the deductible. The practice of not insuring to certain limits, or including deductibles in external insurance policies, is called risk retention. Actuaries distinguish risk retention from self insurance by self insurance's more formal application, as well as risk retention applying to small recurrent risks while self insurance applies to much larger deductibles relative to the value of the loss being covered.[2239]

Regardless of whether the risk is managed by external insurance or self insurance, the risk must be predictable and measurable. This means that it is possible to estimate an amount that needs to be set aside to pay for future uncertain losses (usually by means of actuarial techniques). Premiums represent the periodic allocation of that loss amount. Any approved opex for self insurance is equivalent to an external insurance premium that would otherwise be incurred.

[2236] Finity, *Review of Self Insurance Program: Energex*, pp. i, 3–4, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, pp. i, 5–7, confidential. The AER has taken the definition of attritional losses to mean losses associated with events that are below $2.2 million for Ergon Energy. The definition of attritional has not been made clear in Energex's case, with no dollar amount being stipulated. However, the AER has assumed that attritional damage from storms refers to damage that occurs on a regular basis.

[2237] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 7th Edition, Sydney, 2007, p. 782.

[2238] AER, *Final decision, NSW DNSPs*, 28 April 2009; AER, *Final decision, ACT DNSP*, 28 April 2009; AER, *Final decision, TransGrid*, 28 April 2009; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008; AER, *Final decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007; ACCC, *Final decision, Electranet Transmission network revenue cap 2008–09 to 2012–13*, 14 June 2007; ACCC, *Final decision, NSW and ACT Transmission Network Revenue Cap TransGrid 2004–05 to 2008–09*, 27 April 2005.

[2239] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 2007, p. 781.

Unlike external insurance, in which a lump sum payment for compensation is payable for future losses when the risk event occurs, self insurance requires the network service provider to internally fund the cost of the specified event.

There are several issues the AER needs to consider when assessing proposed self insurance events consistent with the opex criteria, including:

- the attitude of the network service provider to managing risk and its capacity to self insure
- the approaches to funding a future loss when a self insurance event occurs
- the reporting and administration of self insurance.

With respect to the specific self insurance events nominated, the issues to be considered are:

- whether an insurance premium can be determined and whether the self insurance event relates to an incurred cost
- whether the premium estimated is an efficient cost.

The AER considers that these five principles are relevant to the opex objectives and criteria outlined in section 6.5.6 of the NER. In particular, the attitudes to managing risk, the approaches to funding self insurance events and the reporting of events are all directly related to opex objective 6.5.6(a)(3) which states that a building block proposal must include the total costs required to:

> (3) maintain the quality, reliability and security of supply of *standard control services*.

The attitudes to managing risk, the approaches to funding self insurance events and the reporting of events are all directly related to the maintenance of the quality, reliability and security of supply of electricity. Likewise, the AER considers that whether a self insurance premium can be determined and whether this premium is an efficient cost directly relate to clause 6.5.6(c)(3) which states that the AER must accept the proposed costs in the network service provider's regulatory proposal if the AER is satisfied that the proposed expenditure reasonably reflects:

> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

These matters are considered in sections K.2.2 – K.2.6 of this draft decision.

DNSPs attitude to managing risk

Section 6.5.6(c)(2) of the NER requires that forecast opex must reflect the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives. This is relevant for the AER's consideration about the commitment of the DNSP to take on self insurance risks. One of the most difficult aspects of evaluating self insurance is discerning the attitude of the network service provider towards commercial risks and the willingness of the network service provider to accept these risks.[2240]

Self insurance may be via a formal decision not to insure for certain events, which implies any losses will be made up by the network service provider after the event has occurred. The AER considers that a prudent network service provider can demonstrate this attitude by providing verification that the network service provider's board of directors has considered and agreed that certain risks the business faces will be managed by self insurance. Among other things, this can be demonstrated by a board resolution or similar document that provides a formal endorsement supporting the self insurance strategy. This can also be determined by the network service provider's corporate governance procedures and internal approaches to risk management. This does not mean that every network service provider should self insure. However, if it is appropriate, then self insurance should form a part of any comprehensive risk management plan for the relevant business.

Funding of losses when an event occurs

In relation to how losses may be funded, there are two equally acceptable options:[2241]

- setting aside amounts to meet future uncertain losses
- meeting the loss out of current income in the year the loss is incurred.

In a regulatory context, the expectation of the AER in approving the opex allowance for self insurance is that the network service provider will cover the cost of the event, if that event occurs at a future date. Any shortfall will need to be met by the network service provider through internal funding methods rather than compensation through future regulatory revenue.

As future losses may be required to be met from internal funding and will not be compensated by additional regulated revenue, it is imperative that care is taken when self insuring key income generating assets.[2242] In this regard, a key asset is an asset that is crucial to the delivery of services from which the company's income is generated. Without such a key asset, the network service provider's ability to generate income may be severely restricted. The AER recognises that the geographical spread of the Qld DNSPs' networks helps to mitigate risk associated with the inability to fund losses associated with key asset events. However, in general, the AER's preference is that these events are not self insured and that alternative regulatory options such as the cost pass through mechanisms are used if such an event occurs. This ensures that the event can be judged in terms of efficiency and scale once the costs associated with the event are known with certainty.

[2240] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 2007, p. 784.

[2241] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 2007, pp. 784–785.

[2242] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 2007, p. 783.

If key assets are affected, the Qld DNSPs may apply for a cost pass through, subject to the pass through assessment process.[2243] However, in accordance with clause 6.6.1(j)(3) of the NER, the AER must consider the following:

> In the case of a positive change event, the efficiency of the provider's decisions and actions in relation to the risk of the *positive change event*, including whether the provider has failed to take any action that could reasonably be taken to reduce the magnitude of *the eligible pass through amount* in respect of that *positive change even* and whether the provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that *positive change event.*

Accordingly, the AER expects that the Qld DNSPs would mitigate the amount that is proposed to be passed through to customers via a prudent prioritisation of the opex programs. This means that the AER expects that any damage done to the network would be addressed through the pool of funds that would be approved as an efficient level of storm response opex (or equivalent cost category). As the Qld DNSPs will not know the final incurred cost of the event at the time the event manifests, the AER expects that any damage to network assets would be addressed in this fashion, irrespective of whether the event is eventually considered a material cost pass through event or not.

Reporting and administrative arrangements

The AER considers that Australian Accounting Standards are the relevant benchmark for industry best practice with respect to reporting and administration. The AER notes that self insurance events are similar in nature to contingent liabilities. Contingent liabilities are defined under Australian Accounting Standards Board (AASB) 137:[2244]

> a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of an entity.

The standard defines contingent liabilities as liabilities that are not recognised as they are either a possible obligation which is yet to be confirmed or a present obligation which cannot be reliably estimated or is not probable.[2245]

Under AASB 137, self insurance events cannot be a recognised as a provision because there is no present obligation, no probable outflow of resources and no reliable estimate of the amount of the obligation.[2246] However for contingent liabilities the standard does require that certain disclosures are made in the financial accounts of the business.

In the absence of any other administrative arrangements, the AER considers a prudent network service provider should disclose self insurance events each regulatory year and provide a brief description of the nature of the self insurance event in accordance with AASB 137 in its regulatory and audited financial accounts. AASB 137 requires

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[2243] Refer chapter 15 for details on cost pass throughs.
[2244] AASB 137, *Provisions, contingent liabilities and contingent assets*, paragraph 10.
[2245] AASB 137, *Provisions, contingent liabilities and contingent assets*, paragraph 13(b).
[2246] AASB 137, *Provisions, contingent liabilities and contingent assets*, paragraph 14.

the business, where practical, to also disclose an estimate of the financial effect of the liability, an indication of the uncertainties relating to the amount or timing of the outflow, and the possibility of any reimbursement.

When a self insurance risk manifests, the AER considers a prudent network service provider will have in place appropriate reporting procedures to inform the AER that an event has occurred. This report would necessarily provide an estimate of the cost of the event that is supported by independent audit information and verification about how these costs are segregated from regulated revenue.

Thus, the AER considers that when a self insurance event occurs it is preferable that the event is reported as soon as possible. The AER considers that any notification also needs to outline the following information for each event:

- the nature of the event
- the total cost of the event, separately identifying:
  - costs that are provided for by external funding such as through insurance or where the cost is paid for by third parties
  - costs that are covered by self insurance
  - costs to be passed through
  - other costs, for example which do not relate to the regulated assets
- independently verifiable information to justify the estimated total cost of the event and funding components of the total cost used to cover the loss.

Underlying risk being self insured

Industry best practice stipulates that a risk is insurable if the risk is predictable and measurable.[2247] This is primarily about whether the network service provider can establish a reasonable insurance premium for the proposed self insured event. Industry best practice requires that forecast costs can be measured or estimated with some accuracy and are predictable so that the costs are appropriately considered as incurred costs in the regulatory control period. However, an insurable risk cannot be considered in isolation to the regulatory framework, which places constraints on what costs may be included in forecast expenditure for regulatory purposes. This means that not all insurable risks will be costs that are incurred and relevant for determining total revenue allowances. As a result the AER needs to establish that the risk is insurable (so a self insurance premium can be determined) and that it is an incurred cost relevant to regulated services. That is, the self insurance premium must be in relation to an event for which there will be an incurred cost recorded amongst the building block components.[2248] In this regard, the AER rejects self insurance for

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[2247] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 2007, p. 780.

[2248] When the self insurance event manifests, the event must be directly attributable to an incurred cost among one of the building block components. Following this logic, an event such as key person events such as key person risk and business interruption, which relate to a loss of value, rather than an incurred cost for regulatory purposes.

Further, such an incurred cost must not be provided for in another building block item. For example, self insurance must not be approved to cover systematic risk as systematic risks are provided for in the return on capital building block.

Basis for determining the efficient self insurance premium

Once it can be established that the defined risk is insurable under the regulatory framework (the risk relates to an event for which there is an incurred cost under the NER), the premium must be estimated for the proposed self insurance event. As with any forecast opex category, the onus is on the network service provider to justify forecast opex for self insurance against the elements of the opex criteria. This requires establishing that the estimate for the self insurance premium reasonably reflects the efficient costs that a prudent operator would require to achieve the opex objectives. In order to justify the opex for self insurance, it is necessary to demonstrate that sound actuarial techniques have been used to derive the estimate.

The basic premise of self insurance is that a network service provider has a different view of risks (both its ability to manage the risks and the pricing of the risks) than an insurance company. For example, the network service provider believes it can self insure for a lower cost than would be incurred if it externally insured the same event. In some cases an external insurance market may not establish an efficient premium. A network service provider may seek to self insure if it cannot get external insurance on reasonable terms or for a reasonable price. This may be because the risk is business specific, which is difficult to diversify, or the potential losses may be too large for the risk appetite of commercial insurance markets. As the AER outlines in its analysis of particular events, it considers these types of uninsurable or difficult to insure risks, if material, are best considered as a cost pass through event.

However, in some cases risks can be diversified more effectively by external insurers. Risks such as public liability, theft, motor vehicle insurance, trade creditors insurance and certain property insurance, can be clearly defined and a discernable premium determined. In this case, where an existing external insurance policy is in place and the network service provider is seeking to self insure part of the cost of the event (the deductible), the current insurance policy premium may be used as a maximum efficient cost benchmark to establish the self insurance premium. The external insurance premium is a maximum efficient cost benchmark as network service providers have a different view of risks than external insurers or they think they can self insure for less than an external insurance policy would cost.[2249] Thus, where an existing external insurance policy is in place and the network service provider is seeking to self insure part of the cost of the event, the current insurance policy premium should be used as a benchmark to establish the efficient self insurance premium.

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risk where the loss is judged as a loss of value, but not an incurred expense amongst the building block components, would be rejected.

[2249] D.G. Hart, R.A. Buchanan, B.A. Howe, *The Actuarial Practice of General Insurance*, 2007, p. 782.

K.2.2 Assessment of Qld DNSP proposals

The AER has assessed the proposed self insurance premiums by considering the relevant opex criteria and other relevant factors outlined in section K.2.1.

Self insurance for certain events has been considered in previous ACCC and AER decisions. Specifically, the AER made certain decisions regarding self insurance for DNSPs under the NEL and NER in its NSW electricity distribution determinations.[2250]

However, the AER has further developed its position on self insurance for certain items including whether the self insurance premium is connected with an insurable risk and meets the opex criteria under clause 6.5.6 of the NER.

The capacity and commitment of the Qld DNSPs to self insure, the approaches to funding a potential loss and the reporting and administration of self insurance events are considered for each of the self insurance events proposed by the Qld DNSPs. Following this assessment, the AER has considered whether an insurance premium can be determined and whether the underlying risk being insured relates to an incurred cost. Finally, the AER has considered whether the estimated premium represents an efficient and prudent cost.

The AER has not assessed any self insurance events for which the Qld DNSPs have not proposed a self insurance allowance.

K.2.3 Self insurance events – property damage (storm catastrophe)

Energex proposed a $9.1 million premium for storm catastrophe damage over the next regulatory control period.[2251] Ergon Energy proposed a $5.0 million premium for storm catastrophe damage over the next regulatory control period.[2252] Both proposed premiums for storm catastrophe damage were primarily concerned with damage to the distribution networks, for which the Qld DNSPs are currently uninsured.[2253]

K.2.3.1 Attitude and capacity to self insure

The AER accepts the Board Memorandum provided by Energex as evidence of its attitude and capacity to self insure.[2254]

The AER accepts the Board Minute provided by Ergon Energy as evidence of its attitude and capacity to self insure.[2255]

K.2.3.2 Approach to funding future losses

Funding of future losses can be covered by setting aside current income and maintaining a fund over time or being paid from future income. This is the choice of the business, and as a notional or provisional fund cannot be accommodated by

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[2250] AER, *Final Decision: NSW DNSPs*, 28 April 2009.
[2251] Finity, *Review of Self Insurance Program: Energex*, p. 14, confidential.
[2252] Finity, *Review of Self Insurance Program: Ergon Energy*, p. 14, confidential.
[2253] Finity, *Review of Self Insurance Program: Energex*, p. 14, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, p. 14, confidential.
[2254] Energex, *Board memorandum 23/02/2009*, confidential.
[2255] Ergon Energy, *Minutes of the board meeting 27/03/2009,* confidential.

Australian Accounting Standards, businesses generally choose to fund future losses from future income at the time of the loss. The Qld DNSPs did not outline any arrangements for funding future losses, so the AER has assumed that any future losses incurred by the Qld DNSPs will be funded from future income.

While this is a generally accepted method of funding loss events, the AER considers that care must be taken when self insuring key income generating assets. Once an asset is destroyed or is severely impaired, there is a risk that there will be no income or means to fund the self insurance event. If a DNSP loses a key asset and is unable to earn income as a result, even a modest repair or replacement bill could be unpayable. This is in contrast to external insurance, where the losses are funded by an external party or insurer, and is not required to be funded from the income flow (or key income producing assets) of the business. In general, the AER considers that events affecting key income generating assets are better dealt with through the cost pass through mechanism. This ensures that the event can be judged in terms of efficiency and scale once the costs associated with the event are known with certainty.

K.2.3.3 Reporting and administration

The AER notes that neither Energex nor Ergon Energy included any information about administrative arrangements for the management of self insurance in their proposals. The AER considers that self insurance should be reported as a contingent liability as required in accordance with AASB 137, as well as presenting the information outlined in section K.2.1 of this draft decision.

In the case of Ergon Energy, Finity stipulated a demarcation which defines where attritional storm damage becomes a self insured event ($2.2 million per event).[2256]

Energex has not made such a distinction.[2257] However, in the case of Energex, Finity stated that any storm which has a likelihood of occurring of greater than one in four years has been included in the attritional opex forecast.[2258] The AER has concerns about the definitions used by Finity regarding whether an event will be classed as a self insurance event or as an attritional opex event. In particular, as there is no monetary demarcation that separates the self insurance claims from the attritional opex items it is unclear whether an event will be reported as a self insurance event or an attritional storm opex event. The AER is also concerned that, if wind speeds are to be used as the determinant of how an event is recorded, there may be inconsistencies surrounding how and where the wind speeds are measured.[2259]

K.2.3.4 Determining a premium and determining the efficient premium

Finity stated that Energex and Ergon Energy are uninsured for storm catastrophe damage primarily due to the aversion of commercial insurance markets to insure these

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[2256] Finity, *Review of Self Insurance Program: Ergon Energy*, p. 5, confidential. The AER has taken the definition of attritional losses to mean losses associated with events that are below $2.2 million for Ergon Energy. The definition of attritional has not been made as clear in Energex's case, with no dollar figure per event being stipulated. However, the AER has assumed that attritional damage from storms refers to damage that occurs on a regular basis.

[2257] Finity, *Review of Self Insurance Program: Energex*, p. 4, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, p. 6, confidential.

[2258] Finity, *Review of Self Insurance Program: Energex*, p. 4, confidential.

[2259] Finity, *Review of Self Insurance Program: Energex*, pp. 12–15, confidential.

kinds of assets.[2260] As commercial insurance markets are unwilling to insure these assets the AER is concerned about the Qld DNSPs self insuring for these risks. As risk taking is not the core business of DNSPs, the network service provider should be more conservative than an insurance company in its approach to self insuring. If a commercial insurance company, with a diversified insurance portfolio, is unwilling to take on the risks associated with damage to the networks, the AER considers that it is not prudent for a network service provider to self insure, and internally fund, any losses arising from events that damage the network.[2261] Additionally, Finity has stated that the reticence of commercial insurers to insure these assets is due primarily to the size of the exposures and the difficulties in pricing them.[2262] The AER considers that this calls into question the ability of the Qld DNSPs to predict and measure the risk events, and thus their capacity to derive a reliable premium. The AER does not consider a reliable estimate for a self insurance premium can be determined.

The Qld DNSPs have proposed controllable opex allowances for storm damage in their opex forecasts on the basis of historical trends.[2263] Energex proposed an allowance for the next regulatory control period of $45 million ($2009–10) for emergency response/storms and Ergon Energy proposed an allowance for the next regulatory control period of $206 million ($2009–10) for forced maintenance.[2264] The AER considers that in both cases, these costs are based upon the historical incurred costs associated with emergency response/storms and forced maintenance.[2265] These costs reflect the total opex that was incurred in relation to these categories in the current regulatory control period.

As the nature of storms is highly variable, some years the DNSPs will overspend and some years the DNSPs will underspend. The AER considers the DNSPs should be able to prudently and efficiently prioritise their opex, which may include directing resources to network repairs following storm damage.

If the costs meet the pass through criteria outlined in chapter 15 of this draft decision, then the Qld DNSPs could also apply to recoup losses through a cost pass through. If a cost pass through were to be considered, according to clause 6.6.1(j)(3) of the NER the AER must consider the actions of the Qld DNSPs to reduce the magnitude of the cost pass through.

[2260] Finity, *Review of Self Insurance Program: Energex*, p. 6, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, p. 2, confidential.

[2261] Insurance companies are able to pool risks and achieve the benefits of diversification. This diversification is not available to network service providers that choose to self insure.

[2262] Finity, *Review of Self Insurance Program: Energex*, p. 2, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, p. 2, confidential.

[2263] The categories used by the Qld DNSPs are: Energex – emergency response/storms, Ergon Energy – forced maintenance. The AER understands that these categories are largely made up of costs associated with forced maintenance caused by storms. Energex, email response, issue number AER.EGX.09.01, 9 September 2009, confidential; and Ergon Energy, email response, issue number AER.ERG.11.04, 15 September 2009, confidential.

[2264] Refer Energex, RIN proforma, 2.2.2 and Ergon Energy, RIN proforma, 2.2.2. Energex states in RIN proforma 2.2.2 that emergency response/storms includes field work to repair storm damage.

[2265] Energex, *Regulatory Proposal*, July 2009, p. 167; Energex, email response, PB.EGX.VP.40; and Ergon Energy, *Regulatory Proposal*, July 2009, pp. 275–278.

The AER considers that the Qld DNSPs should prioritise their opex programs prudently as part of every day business. This should include actions such as preventative maintenance that may serve to mitigate the impact or cost of potential pass through events. This would be in line with opex objectives (3) and (4) outlined in clause 6.5.6 of the NER. These objectives state that a DNSP must forecast the opex required to:

> (3) maintain the quality, reliability and security of supply of standard control services
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In addition, assuming the Qld DNSPs do not receive funding for self insurance or external insurance cover, any capex associated with replacing assets damaged by storm will be recouped by adding the value of actual capex to the regulatory asset base. The incurred loss is therefore not the total capex to replace an asset, but rather the foregone return on the asset in the lead up to rolling the replacement asset's value into the regulatory asset base which would occur at the commencement of the subsequent regulatory control period. Additionally, the depreciation on the assets destroyed by storm would also continue to be recouped even though these assets may no longer be providing a service.

The AER has concerns about some of the assumptions and methodologies used by Finity in deriving the probabilities and costs associated with catastrophic storm damage. For example, Finity has included the costs and probabilities associated with Cyclone Larry in the derivation of Ergon Energy's storm costs.[2266] Ergon Energy was successful in applying to pass through costs associated with Cyclone Larry.[2267] As Cyclone Larry was considered a sufficiently material event to be pass through to customers, the AER considers that inclusion of data associated with Cyclone Larry for the purposes of deriving a self insurance premium is unsatisfactory. Any data associated with an event that was considered a cost pass through event should be excluded for the purposes of deriving a self insurance premium.

Finity have also not sufficiently explained why they have assumed a maximum wind speed for Cyclone Larry of 200 km/h, when the official Bureau of Meteorology recorded gusts of 185 km/h.[2268] This seems an inconsistent position, as Finity have accepted the Bureau of Meteorology's data in most other respects. The AER considers this discrepancy in data detracts from the derivation of an efficient self insurance premium.

Finity has also assumed that as the storms in 2004 did more damage to the Energex network than the December 2007 storms, the 2004 storms had stronger wind speed.[2269] The AER does not consider that this assumption is robust, as it does not take into account condition of equipment damaged, and the possible effects of storm

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[2266] Finity, *Review of Self Insurance Program: Ergon Energy*, appendix E, confidential.
[2267] QCA, *Final Decision: Cost Pass Through Application Ergon Energy – Tropical Cyclone Larry*, September 2008.
[2268] Finity, *Review of Self Insurance Program: Ergon Energy*, appendix E, confidential.
[2269] Finity, *Review of Self Insurance Program: Energex Limited*, appendix C, confidential.

mitigation work, such as Energex's extensive vegetation management program. The AER considers that if no data is available for the storm being considered, then that storm should be excluded from the study in order to obtain a conservative estimate.

In accordance with 6.5.6(c)(3) of the NER, the AER considers that inclusion of assumptions and methodologies such as those used by Finity do not produce a realistic expectation of the cost inputs required to achieve the opex objectives.

K.2.3.5 Summary

In conclusion, the AER considers that the appropriate self insurance premium for property damage for the Qld DNSPs is $0 for the following reasons:

- Energex has not stipulated a measurable threshold, such as a dollar amount, for each event where attritional damage events become a self insurance event. As such the AER is unsure of how an event will be treated when it occurs, and is concerned about inconsistencies surrounding the application of the one in four year thresholds

- the risk does not appear to be predictable and measurable and thus the AER cannot be certain that the proposed premium accurately reflects the costs incurred by a prudent operator

- the Qld DNSPs have the ability to cover non–material losses through their opex and capex programs

- Finity has used data relating to a cost pass through event (Cyclone Larry) in determining the self insurance premium for Ergon Energy. As this event was considered a cost pass through, the AER considers that data relating to this event should not be used to determine a self insurance premium

- Finity's assumption of a 200 km/h maximum wind speed gusts in determining Ergon Energy's self insurance premium are not satisfactory, and do not produce a realistic expectation of the cost inputs required to achieve the opex objectives

- Finity's assumptions regarding the 2004 storms, and the inclusion of these storms in the data set is unsatisfactory and does not produce a realistic expectation of the cost inputs required to achieve the opex objectives.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposals, the AER is not satisfied that the self insurance premiums proposed in relation to storm catastrophe damage reasonably reflect the opex criteria, including the opex objectives. The AER considers that its adjustments are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the self insurance principles outlined in section K.2.1 and the opex factors.

While the AER does not consider the self insurance premiums appropriate, it considers that in the event of a material loss, Energex and Ergon Energy may be able to seek a cost pass through when the timing and the cost estimates of the event are known with certainty.

Table K.2: Energex and Ergon Energy self insurance for property damage (storm catastrophe) ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed	1.6	1.6	1.8	1.9	1.6	8.5
AER adjustments	–1.6	–1.6	–1.8	–1.9	–1.6	–8.5
Total self insurance	0	0	0	0	0	0
Ergon Energy proposed	1.1	1.1	1.1	1.1	1.1	5.3
AER adjustments	–1.1	–1.1	–1.1	–1.1	–1.1	–5.3
Total self insurance	0	0	0	0	0	0

Source: Finity, *Review of Self Insurance Program: Energex*, p. ii, confidential; and Finity, *Review of Self Insurance program: Ergon Energy*, pp. iii, confidential and Ergon Energy, email response, 18 November 2009, confidential.

K.2.4 Self insurance events – public liability risk

Energex proposed a self insurance premium for public liability (large losses). Finity defined a large loss as one that costs more than $[redacted] million. The external insurance policy held by Energex covers public liability claims in excess of $[redacted] million dollars. Thus all costs outlined in Energex's self insurance proposal are associated with claims between $[redacted] million and $[redacted] million. Finity used customer number growth as a measure of exposure to public liability claims.[2270] The total premium proposed by Energex in relation to public liability (large losses) for the next regulatory control period is $6.8 million. This includes a premium of $2 million relating to fire liability.[2271]

Ergon Energy advised that it currently holds an insurance policy for public liability, with a $[redacted] million deductible per event, and a $[redacted] million aggregate deductible per year. Ergon Energy proposed three categories of public liability:[2272]

- public liability (attritional) – excludes bushfire; proposed premium over next regulatory control period – $11.9 million
- public liability (large claims) – excludes bushfire; proposed premium over next regulatory control period – $4 million
- public liability (bushfire) – proposed premium over next regulatory control period – $0.7 million.

[2270] Finity, *Review of Self Insurance Program: Energex*, p. 15, confidential.
[2271] Energex, email response, issue number AER.EGX.09.05, 9 September 2009, confidential.
[2272] Finity, *Review of Self Insurance program: Ergon Energy*, pp. 17–21, confidential.

K.2.4.1 Attitude and capacity to self insure

The AER accepts the Board Memorandum provided by Energex as evidence of its attitude and capacity to self insure.[2273]

The AER accepts the Board Minute provided by Ergon Energy as evidence of its attitude and capacity to self insure.[2274]

K.2.4.2 Approach to funding future losses

The Qld DNSPs did not outline any arrangements for funding future losses, so the AER has assumed that any future losses incurred by the Qld DNSPs will be funded from future income.

The AER considers that the Qld DNSPs would be able to fund liability claims from future income, as a public liability event would not impact on the operation of their main income generating assets.

K.2.4.3 Reporting and administration

The AER notes that neither Energex nor Ergon Energy included administrative arrangements for the management of self insurance in their regulatory proposals. The AER considers that self insurance should be reported as a contingent liability as required in accordance with AASB 137, as well as providing the information outlined in section K.2.1 of this draft decision.

K.2.4.4 Determining a premium and determining the efficient premium

Finity included an estimate of claims incurred but not yet reported (IBNR) for both Energex and Ergon Energy. Finity stated that this was done because "claims can take many years to settle, especially where litigation is involved." Finity was unable to obtain estimates of this provision from either Energex or Ergon Energy, and used internal benchmarks to estimate such claims.[2275]

Finity has outlined the size of the IBNR factor for Ergon Energy's attritional public liability losses and Energex's public liability (large) category. However, Finity has not shown the IBNR factor for Ergon Energy's public liability (large claims) category. In addition, it has not outlined how these benchmarks have been derived, nor whether these are industry specific or more general benchmarks. The AER is unclear on how these benchmarks relate to the Qld DNSPs. The use of a benchmark that is not directly applicable to the electricity distribution industry cannot be relied on to derive the most efficient costs that a prudent operator would incur. The AER considers that the use of benchmarks in this manner is inconsistent with the self insurance assessment principle of determining the efficient cost of a business specific risk.

[2273] Energex, *Board memorandum 23/02/2009*, confidential.
[2274] Ergon Energy, *Minutes of the board meeting 27/03/2009,* confidential.
[2275] Finity, *Review of Self Insurance Program: Energex*, p. 16, confidential; and Finity, *Review of Self Insurance program: Ergon Energy*, p. 20, confidential.

The AER was provided a copy of Energex's insurance renewal report.[2276] Using these external insurance policies as a guide, the AER has analysed the efficiency of Energex's proposed premiums for public liability self insurance. The report states that for $[redacted] million of public liability coverage, the external insurance premium will be $[redacted] million per annum.[2277] The self insurance premium proposed by Energex to cover public liability claims is $6.8 million, or an average of $1.4 million per annum. This will be for $[redacted] million worth of coverage.[2278] Using the primary liability insurance policy held by Energex as a proxy, the average cost to obtain $[redacted] million in liability coverage is $7528 per annum.[2279] The AER recognises that the deductible will have a higher premium associated with it due to the higher probability of events occurring in this lower cost band. This is compared to events over the $[redacted] million deductible, which, as the liability cost goes higher, has a decreasing probability of occurring and thus attracts a lower premium per dollar insured.

However, in the absence of a formal quote illustrating the costs to externally insure the deductible, or the provision of similar information, the AER will use the premium paid on external insurance policies as an estimate of the efficient premium. The self insurance premium proposed by Energex is almost twice the external insurance premium paid. The AER thus considers that the self insurance premiums proposed for public liability are not efficient.

The AER considers that the efficient self insurance premium for general public liability for Energex is therefore $7528 per annum for the next regulatory control period.

Ergon Energy's report on self insurance did not refer to the insurance premiums that are currently being paid on its external insurance policies for similar risks. However, in response to AER enquiries, Ergon Energy provided the AER with a summary of its public liability external insurance policy.[2280] Ergon Energy advised it currently pays a premium of $[redacted] million for $[redacted] million of external public liability coverage. The deductible on this external insurance policy is $[redacted] million per annum in aggregate.[2281] The self insurance premium proposed by Ergon Energy to cover the $[redacted] million deductible was $16.6 million for the next regulatory control period.[2282] Using the primary liability insurance policy held by Ergon Energy as a proxy, the average cost to obtain $[redacted] million in liability coverage is $3218 per annum.[2283] The AER

2276 Willis Australia Limited, *Energex Ltd: Insurance Renewal Report: Period of Insurance 30/09/2008 to 30/09/2009*, 26 September 2008, confidential.

2277 Willis Australia Limited, *Energex Ltd*, 26 September 2008, pp. 21–31, confidential. The liability policies that Energex has includes several layers of public liability insurance. In order to determine a proxy rate for the self insurance premium, the AER has utilised the primary liability insurance policy.

2278 This is because it is stated in the Finity report that Energex include any liability claim under $0.1 million per event in the forecast network operating expenditure. Refer Finity, *Review of Self Insurance Program: Energex*, p. ii and 15, confidential.

2279 Willis Australia Limited, *Energex Ltd*, 26 September 2008, pp. 21–22, confidential.

2280 Ergon Energy, email response, issue number AER.ERG.11.03, 15 September 2009, confidential.

2281 Finity, *Review of Self Insurance program: Ergon Energy*, p. 9 and 17, confidential.

2282 Finity, *Review of Self Insurance program: Ergon Energy*, p. ii, confidential.

2283 Ergon Energy, email response, issue number AER.ERG.11.03, 15 September 2009, confidential.

recognises that the deductible will have a higher premium associated with it due to the higher probability of events occurring in this lower cost band. This is compared to events over the $[redacted] million deductible, which, as the liability cost goes higher, have a decreasing probability of occurring and thus attract a lower premium per dollar insured.

However, in the absence of a formal quote illustrating the costs to externally insure the deductible, or the provision of similar information, the AER will use the premium paid on external insurance policies as an estimate of the efficient premium. The self insurance premium proposed by Ergon Energy for the three liability categories are almost five times the external insurance premium paid. The AER thus considers that the self insurance premiums proposed for public liability are not efficient.

The AER considers that the efficient self insurance premium for general public liability for Ergon Energy is therefore $3218 per annum for the next regulatory control period.

K.2.4.5 Summary

The AER rejects Energex's proposed self insurance premiums for public liability and considers that the efficient premium for Energex's general public liability category is $7528 per annum for the following reasons:

- the application of the IBNR benchmarks are not appropriate.
- using the external insurance policies as a maximum efficient benchmark cost, the AER has determined that the premiums proposed by Energex are not efficient
- using a proportionate analysis, the AER has derived an estimate of a premium to cover the deductible for general public liability.

The AER rejects Ergon Energy's proposed self insurance premiums for public liability and considers that the efficient premium for Ergon Energy's general public liability category is $3218 per annum for the following reasons:

- the application of the IBNR benchmarks are not appropriate
- using the external insurance policies as a maximum efficient benchmark cost, the AER has determined that the premiums proposed by Ergon Energy are not efficient
- using a proportionate analysis, the AER has derived an estimate of a premium to cover the deductible for general public liability.

For the reasons discussed and as a result of the AER's analysis of the Qld DNSPs' regulatory proposals, the AER is not satisfied that the self insurance premiums proposed in relation to public liability risks reasonably reflect the opex criteria, including the opex objectives. The AER considers that its adjustments are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the self insurance principles outlined in section K.2.1 and the opex factors.

Table K.3: Energex and Ergon Energy self insurance for public liability risks ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed	1.200	1.300	1.300	1.300	1.400	6.500
AER adjustments	–1.192	–1.292	–1.292	–1.292	–1.392	–6.458
Total self insurance	0.008	0.008	0.008	0.008	0.008	0.038
Ergon Energy proposed	3.100	3.100	3.300	3.400	3.500	16.300
AER adjustments	–3.097	–3.097	–3.297	–3.397	–3.497	–16.284
Total self insurance	0.003	0.003	0.003	0.003	0.003	0.016

Source: Finity, *Review of Self Insurance Program: Energex*, p. ii, confidential; and Finity, *Review of Self Insurance program: Ergon Energy*, pp. iii, confidential and Ergon Energy, email response, 18 November 2009.

Note: Totals may not add up due to rounding.

K.2.5 Self insurance events – retailer credit risk

Energex has proposed a total self insurance premium of $0.4 million over the next regulatory control period relating to retailer credit risk. This premium covers any losses that may arise as a result of a retailer defaulting on its payment obligations to Energex.[2284]

K.2.5.1 Attitude and capacity to self insure

The AER accepts the Board Memorandum provided by Energex as evidence of its attitude and capacity to self insure.[2285]

K.2.5.2 Approach to funding future losses

Energex did not outline any arrangements for funding future losses, so the AER has assumed that any future losses incurred by Energex will be funded from future income.

The AER does not have concerns with Energex funding moderate losses associated with retailer default. However, the AER considers that a DNSP would not be able to internally fund losses that are associated with large defaults or defaults from several companies at once. These circumstances would likely be subject to cost pass through, if meeting the relevant pass through criteria.

K.2.5.3 Reporting and administration

The AER notes that Energex did not include any information on administrative arrangements for the management of self insurance in its proposal. The AER considers that self insurance should be reported as a contingent liability as required in

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[2284] Finity, *Review of Self Insurance Program - Retailer Credit Risk*, June 2009, p. 3, confidential.
[2285] Energex, *Board memorandum 23/02/2009*, confidential.

accordance with AASB 137, as well as providing the information outlined in section K.2.1 of this draft decision.

K.2.5.4 Determining a premium and determining the efficient premium

According to Energex, 95 per cent of its network charges for the three months to the end of April come from companies that have credit ratings of BBB– or above. For companies that do not have a credit rating, or are not guaranteed by a parent company with a credit rating, Energex obtains bank guarantees to mitigate any potential losses. Energex advised that it looked into the viability of obtaining commercial insurance in respect to retailer credit risk. However, Energex has found that for some retailers commercial insurance is unavailable.[2286] The AER questions why this is the case, and whether insurance is not available due to the difficulty of deriving a premium for the exposure.[2287] If so, these events fail the principle of being measurable and predictable, and as such cannot be accepted as self insurance events

Further, the AER notes that Energex has not previously experienced any losses associated with a default. Energex has only experienced one default in the past and was able to recoup all associated costs.[2288] The AER therefore considers that, in the absence of historical data, the ability to predict the probability of the event, and measure the resulting loss, is severely limited.

Examining whether a company is provisioning for bad debts is a reliable method of understanding whether a company expects to incur bad debt losses in the near future. Energex did not provide information to confirm it is currently provisioning for bad debts. However, Energex's most recently available financial accounts, as at 30 June 2008, show that Energex was not provisioning for bad debts.[2289] In the absence of further information, the AER cannot determine whether the business expects to incur bad debt losses.

The AER considers that retailer credit risk is a legitimate business specific risk for DNSPs. However, the AER notes the extent and probability of a default event occurring are considered by Finity to be highly uncertain.[2290] This brings into question whether the risk is predictable and measurable. Thus, the AER does not consider that self insurance is the best manner in which to mitigate this particular risk. There are alternative methods available to Energex, including obtaining commercial insurance (if offered), additional security or applying for a cost pass through in the event that a retailer default loss occurs.

K.2.5.5 Summary

In summary, the AER considers that the most appropriate premium for retailer credit risk for Energex is $0 for the following reasons:

- Energex has no prior history of retailer credit risk losses

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2286 Finity, *Review of Self Insurance Program - Retailer Credit Risk*, June 2009, p. 3, confidential.
2287 Finity, *Review of Self Insurance Program - Retailer Credit Risk*, June 2009, p. 3, confidential.
2288 Finity, *Review of Self Insurance Program - Retailer Credit Risk*, June 2009, appendix C.1, confidential.
2289 Energex, *Annual Report 2007–08*, pp. 99–100.
2290 Finity, *Review of Self Insurance Program - Retailer Credit Risk*, June 2009, pp. 9–10, confidential.

- Energex has not provided information on its provisions for bad debts
- there is a high level of uncertainty associated with deriving a premium for retailer credit risk and the AER is not satisfied that the event is predictable and measurable.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, the AER is not satisfied that the self insurance premiums proposed in relation to retailer credit risk reasonably reflect the opex criteria, including the opex objectives. The AER considers that its adjustments are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the self insurance principles outlined in section K.2.1 and the opex factors.

The AER does note, however, that in the event of a retailer credit risk event Energex may be able to apply for a cost pass through.

Table K.4: Energex self insurance for retailer credit risk ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed	0.085	0.08	0.071	0.065	0.059	0.36
AER adjustments	–0.085	–0.08	–0.071	–0.065	–0.059	–0.36
Total self insurance	0	0	0	0	0	0

Source: Finity, *Review of Self Insurance Program - Retailer Credit Risk*, June 2009, pp. i, confidential.

K.2.6 Notional Premium

Both Energex and Ergon Energy provided, using actuarial techniques, a methodology and estimate for a notional insurance premium for the self insurance events identified. However, the notional premiums were calculated using commercial property benchmarks, which are necessarily approximate.[2291]

As there is generally no commercial insurance available for network assets, and the fact that the commercial property benchmarks are approximate, the AER is concerned about the usefulness of applying these benchmarks to determine a notional premium. The AER believes that a far more reliable way of determining the premium for comparison with the proposed self insurance premium is to supply actual insurance quotes for coverage up to the upper limit, including insuring the deductible amount. Alternatively, a rough guide can be determined by examining the current premiums being paid on the external policies, and then calculating what would be paid, via a proportionate analysis, to insure the deductible.

[2291] Finity, *Review of Self Insurance Program: Ergon Energy*, p. 24, confidential; and Finity, *Review of Self Insurance Program: Energex*, p. iii, confidential.

K.3 AER conclusion

Having reviewed the analysis by Energex and Ergon Energy's actuarial consultant, Finity Consulting, the AER is not satisfied that the proposed self insurance premiums reasonably reflect the opex criteria, including the opex objectives. The AER considers that its adjustments are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the self insurance principles set out in section K.2.1, and the opex factors.

Table K.5 summarises the Qld DNSPs proposed self insurance premiums and the AER's conclusion on self insurance premiums.

Table K.5: Self insurance allowances ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed	2.800	2.900	3.100	3.200	3.000	15.100
AER adjustments	–2.792	–2.892	–3.092	–3.192	–2.992	–15.060
Total self insurance	0.008	0.008	0.008	0.008	0.008	0.038
Ergon Energy proposed	4.152	4.159	4.276	4.393	4.514	21.504
AER adjustments	–4.149	–4.159	–4.276	–4.393	–4.512	–21.488
Total self insurance	0.003	0.003	0.003	0.003	0.003	0.016

L. Benchmark debt raising costs

L.1 Introduction

This appendix deals with debt raising costs, which are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has accepted that debt raising costs are a legitimate expense for which a DNSP should be provided an allowance.[2292]

The AER concurrently assessed the regulatory proposals of three DNSPs:

- Energex and Ergon Energy (the Qld DNSPs)
- ETSA Utilities.

L.2 Regulatory requirements

Although these regulatory proposals are assessed under two separate decisions, the consideration of appropriate benchmark debt raising costs is a common matter.

The revenue and pricing principles set out that each of the DNSPs should be provided with the opportunity to recover at least its efficient costs.[2293] It is also pertinent that regard should be had to the potential for under or over investment, a matter that may be materially impacted by debt raising costs.[2294] The opex criteria require that the total opex forecast reasonably reflects the efficient costs and the costs that a prudent operator in the circumstances of the relevant DNSP would require.[2295] Further, the forecast opex is assessed with regard to the benchmark opex that would be incurred by an efficient DNSP over the regulatory control period.[2296]

The AER has jointly assessed the benchmark debt raising costs of all three DNSPs on this basis. In particular, where consultant reports have been submitted by one of the DNSPs, to the extent that the information is pertinent to all DNSPs the information has been jointly considered within this appendix.

For convenience, within this appendix references to the benchmark firm should be interpreted as a reference to a benchmark efficient DNSP that is a pure play regulated electricity network operating in Australia without parent ownership.

Where it has been necessary to refer to a draft decision for just one of the DNSPs, within this appendix the AER has identified the specific business when referencing

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[2292] AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, pp. 148–150 and *AER, Final decision, ElectraNet transmission determination* 2008–09 to 2013–14, 11 April 2008, pp. 84–85.

[2293] For electricity, this means efficient costs associated with direct control network services and regulatory obligations; see NEL, section 7A.

[2294] NEL, section 7A(6).

[2295] NER, clauses 6.5.6(c)(1) and 6.5.6(c)(2).

[2296] NER, clause 6.5.6(e).

the draft decision, rather than referring to the generic term draft decision, as defined in the shortened forms.

Past AER considerations

In April 2009, the AER released final decisions (April 2009 final decisions) covering regulatory and revenue determinations for electricity distribution and transmission networks in NSW, ACT and Tasmania which included a common appendix dealing with benchmark debt and equity raising costs.[2297] The April 2009 appendix to the final decisions sets out the AER's analysis and considerations with regard to the efficient costs of raising capital prior to the commencement of the current processes.

For simplicity, references to the April 2009 final decisions in this appendix are made to the ACT final decision only.

L.3 Regulatory proposals

The DNSPs proposed that the cost of debt raising be benchmarked as a cost per year per dollar of allowed debt associated with their regulatory asset bases—that is, the gearing ratio times the regulatory asset base. The proposals were:

- the Qld DNSPs proposed an allowance of 15.5 basis points per annum (bppa), comprising 12.5 bppa for direct debt raising costs and 3.0 bppa for indirect raising costs[2298]

- ETSA Utilities proposed an allowance of 23.2 bppa, comprising 12.0 bppa for direct debt raising costs and 11.2 bppa in additional debt raising costs associated with the 'completion method'.[2299]

The DNSPs included various arguments in their regulatory proposals to support these debt raising cost benchmarks. Additionally, further consultant reports were submitted:

- the Qld DNSPs submitted a report by Synergies Economic Consulting (Synergies) that deals with debt and equity raising costs[2300]

- ETSA Utilities submitted a report by CEG that deals with debt and equity raising costs[2301]

[2297] AER, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April 2009, appendix H; AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, appendix N; AER, *Final decision, TransGrid transmission determination 2009–10 to 2013–14*, 28 April 2009; AER, appendix E; AER, *Final decision, Transend transmission determination 2009–10 to 2013–14*, 28 April 2009, appendix E.

[2298] Energex, *Regulatory proposal*, July 2009, section 12.7.4, p. 173. Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.1, pp. 305–306.

[2299] ETSA Utilities, *Regulatory proposal*, July 2009, p. 155.

[2300] Synergies Economic Consulting, *Debt and equity raising costs: Report for Energex and Ergon Energy*, May 2009. Submitted as attachment 12.5 to the Energex regulatory proposal and attachment 534c to the Ergon Energy regulatory proposal.

[2301] CEG, *Debt and equity raising costs: A report for ETSA*, June 2009. Submitted as attachment E.17 to the ETSA regulatory proposal.

- ETSA Utilities submitted a separate confidential attachment dealing with the 'completion method'.[2302]

Submissions relevant to debt raising costs were received from:

- Energy Consumers Coalition of South Australia (ECCSA) on the ETSA Utilities proposal.[2303]
- Energy Users Association of Australia (EUAA) on the Energex proposal.[2304]

The AER's analysis of debt raising costs in this appendix covers:

- indirect debt raising costs
- direct debt raising costs.

Debt raising costs associated with the 'completion method' are specific to ETSA Utilities and are discussed in a separate confidential appendix to the ETSA Utilities draft decision.

L.4 Issues and AER considerations

L.4.1 Indirect debt raising costs

Regulatory proposals

The Qld DNSPs proposed an indirect debt raising cost of 3.0 bppa on the basis of the Synergies report.[2305] ETSA Utilities did not propose an indirect debt raising cost allowance.

AER considerations

The AER has previously considered the issue of indirect debt raising costs (also labelled as underpricing).[2306] The key issue was whether the basis for the debt risk premium (yields observed in the secondary market) accurately reflected the cost to the initial debt issuer. The AER considered that using fair yield curves to estimate the cost of debt for the benchmark regulated firm produced a best estimate that encapsulated any underpricing effect. Providing an indirect debt raising cost allowance based on this approach would systematically over compensate the service provider:[2307]

[2302] ETSA Utilities, *Regulatory proposal*, July 2009, confidential appendix F.14.

[2303] ECCSA, *Australian Energy Regulator, SA electricity distribution revenue reset: ETSA Utilities application, a response*, August 2009, p. 37.

[2304] EUAA, *Submission to the AER on Energex and Ergon Energy regulatory proposals for the period 2010–2015*, 28 August 2009, p. 20.

[2305] Energex, *Regulatory proposal*, July 2009, p. 173, section 12.7.4. Ergon Energy, *Regulatory proposal*, July 2009, pp. 305–306, section 28.2.1.

[2306] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; pp. 214–221.

[2307] AER, *Final decision, TransGrid*, 28 April 2009, p. 137; AER, *Final decision, NSW DNSPs*, p 186; and AER, *Final decision, Transend*,28 April 2009, p. 190.

> If firms effectively issue at a higher yield than BBB+, for example due to underpricing the debt, the firms are effectively issuing higher yielding lower grade debt. The proposed underpricing premium is therefore inconsistent with the assumed BBB+ benchmark.

This was supported by the AER's consultant, Associate Professor Handley of the University of Melbourne, who stated:[2308]

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt, and noting that both the AER and CEG believe this to be the case, then it is my view that, underpricing should not be allowed as a cost of raising debt capital.

The AER found that despite assertions to the contrary, there was an absence of empirical evidence to support a claim for indirect debt raising costs. Further, there was no empirically demonstrated relationship between indirect and direct debt raising costs.[2309] On this basis, the AER did not provide an allowance for indirect debt raising costs in its April 2009 final decisions.[2310]

Synergies defined indirect debt raising costs in a similar manner to the AER,[2311] and observed the difficulties in quantifying indirect debt raising costs.[2312] Synergies submitted that liquidity problems cause indirect costs—that is, it is difficult for the primary issuer of debt to 'get away' a large amount of debt all at once, so a discount (relative to the relevant secondary market rate) must be offered. Further, Synergies stated that the indirect cost of debt raising would be higher given current market conditions, both because there was less liquidity in the market at present, and because market appetite for risk was lower than usual. Synergies also stated that there was an additional indirect cost of raising debt—the impact of restrictive debt covenants that have been imposed on borrowers since the beginning of the GFC.

Synergies did not attempt any quantification of the indirect costs of debt raising. Rather, it cited a May 2008 report by CEG that recommended 3.0 bppa as a benchmark allowance.[2313] Synergies included anecdotal examples of borrowers paying amendment fees and accepting more stringent debt covenants, and an anecdotal reference to the magnitude of debt raising costs:[2314]

> One market issuer we spoke to was of the view that while the difference can vary considerably, it can be as great as 100 basis points.

2308 Handley, J., *A note on the costs of raising debt and equity capital: Report prepared for the Australian Energy Regulator*, 12 April 2009, p. 17.

2309 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; pp. 220–221.

2310 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; AER, *Final decision, NSW DNSPs*, 28 April 2009, appendix N; AER, *Final decision, TransGrid*, 28 April 2009; AER, appendix E; AER, *Final decision, Transend*, 28 April 2009, appendix E.

2311 Synergies, *Debt and equity raising costs*, May 2009, p33, states: 'The difference between the primary market rate and the secondary market rate can be used to estimate indirect debt raising costs.'

2312 Synergies, *Debt and equity raising costs*, May 2009, p33, states: 'The difference is not captured or reported by any financial data provider.'

2313 Synergies, *Debt and equity raising costs*, May 2009, p34, citing CEG, *Nominal risk–free rate, debt risk premium and debt and equity raising costs for TransGrid*, May 2008.

2314 Synergies, *Debt and equity raising costs*, May 2009, p. 33.

The AER considers that Synergies has not presented any new evidence to support the claim for indirect debt raising costs.

The AER has previously considered the CEG report,[2315] and further updated reports from CEG on this issue.[2316] The empirical evidence cited therein does not support a claim for indirect raising costs. In summary, the Datta, Datta and Patel paper find 'underpricing' that was statistically indistinguishable from zero.[2317] The Cai, Helwege and Warga report finds slight overpricing—that is, the indirect cost of debt raising is negative—on the relevant bonds (investment grade bonds that are not part of the initial offering of debt by a firm).[2318] The other academic paper referred to in the CEG report, a working paper by Kim, Palia and Saunders, presents no data on this issue.[2319] The AER notes that the most recent CEG report on debt and equity raising costs—submitted on behalf of ETSA Utilities after the April 2009 final decisions by the AER—makes no claim for indirect debt raising costs, and states:[2320]

> However, in the context of regulation under the NER, provided the interest costs are measured as the interest costs that an issuer would incur then this indirect cost will already be captured in the estimate of interest costs.

The AER considers that, separate from evaluating the plausibility of a liquidity-driven explanation for indirect debt raising costs, no weight can be given to any of Synergies' assertions in the absence of empirical evidence. Similarly, the existence or impact of restrictive debt covenants on the benchmark firm cannot be ascertained from isolated anecdotes.[2321] Further, the reference by Synergies to a 100 basis point indirect debt raising cost (at issuance) does not support a claim for indirect raising costs, since it presents a maximum value separate from any discussion of the cost that might be considered applicable to the benchmark efficient firm.

AER conclusion on indirect debt raising costs

Consistent with its April 2009 final decisions, the AER considers that there is no evidence of indirect debt raising costs for the benchmark bond issue that is relevant to Energex, Ergon Energy or ETSA Utilities.

2315 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; pp. 216–218.

2316 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, pp. 214–220, which includes consideration of CEG, *Debt and equity raising costs: A response to the AER 2008 draft decisions for electricity distribution and transmission (EnergyAustralia version)*, January 2009; and the five variants of the May 2008 CEG report.

2317 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; p. 218; the source paper is Datta, S., Iskandar-Datta, M., and Patel, A., *The pricing of initial public offers of corporate straight debt*, Journal of Finance, vol. 52(1), March 1997, pp. 379–396.

2318 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; pp. 218–219; the source paper is Cai, N., Helwege, J. and Warga, A., *Underpricing in the corporate bond market*, The Review of Financial Studies I, vol. 20(5), 2007, pp. 2021–2046.

2319 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H; pp. 218–219; the source paper is Kim, D., Palia, D., and Saunders, A., *The Long–Run Behaviour of Debt and Equity Underwriting Spreads*, Working Paper, January 2003.

2320 CEG, *Debt and equity raising costs*, June 2009, paragraph 118, p. 30.

2321 The AER notes that this issue is related to that presented in the ETSA Utilities 'completion method' confidential appendix, and therefore some of the discussion of that issue is relevant.

L.4.2 Direct debt raising costs

Regulatory proposals

The Qld DNSPs proposed a direct debt raising cost of 12.5 bppa on the basis of the Synergies report.[2322] ETSA Utilities proposed a direct debt raising cost of 12.0 bppa on the basis of the CEG report.[2323]

AER considerations

In the April 2009 final decisions, the AER applied a methodology based on the 2004 Allen Consulting Group (ACG) report,[2324] updated to incorporate 2008 data. This methodology involved the calculation of the cost of a benchmark bond issue size ($200 million), and the number of such bond issues required to rollover the benchmark debt share (60 per cent) of the regulatory asset base (RAB). The allowance for the benchmark bond issue was based on the direct costs of raising debt, such as underwriting fees, legal fees and credit rating fees.

Debt raising and opex forecasts

The AER notes the submission from the ECCSA regarding the interaction between debt raising costs and the increased opex proposed by ETSA Utilities. The AER considers that the application of its methodology ensures that the allowed debt raising costs do not inappropriately increase the total opex allowance.[2325]

Type of debt funding

The approach applied by the AER (based on the 2004 ACG report) benchmarks direct debt issuance costs on the basis of a firm issuing its own debt as medium term notes (MTN). Synergies stated that this is an inappropriate benchmark:

> The MTN market is only a subset of the corporate bond market and in our view it is considered inappropriate to solely rely on this market to establish a benchmark allowance for debt raising costs.[2326]

Synergies' primary concern was not that MTN do not reflect the bond market more generally, but that the cost of issuing MTN does not reflect the cost of accessing bank debt. Synergies analysed firms listed on the Utilities Index in the United States and found that all firms had some bank debt, with an average 60 per cent of interest bearing debt held as syndicated or bank debt.[2327] Synergies therefore considered that the benchmark firm would also require this form of funding, and presented an indicative range of 30 to 40 bppa for the cost of accessing bank debt.[2328]

[2322] Energex, *Regulatory proposal*, July 2009, section 12.7.4, p. 173. Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.1, pp. 305–306.
[2323] ETSA Utilities, *Regulatory proposal*, July 2009, p. 155.
[2324] ACG, *Debt and equity raising transaction costs: Final report to the ACCC*, December 2004.
[2325] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 37.
[2326] Synergies, *Debt and equity raising costs*, May 2009, p. 38.
[2327] Synergies, *Debt and equity raising costs*, May 2009, p. 35.
[2328] This range is derived from eight large US debt issues (in the absence of Australian data), although it is not clear if any mathematical operation (average or median) was applied. Synergies, *Debt and equity raising costs*, May 2009, pp. 35–36, table 10.

The AER considers that explicit consideration of the cost and prevalence of the range of alternative debt options was already undertaken by ACG in its 2004 report, which specifically considered project finance, term loans and revolving loans (all relevant to the more general 'bank debt' label applied by Synergies).[2329] ACG concluded that the benchmark debt raising cost should be based on the bond market since, as the cheapest source of debt, it would be accessed first by the benchmark firm.[2330] Indeed, Synergies accepted that this funding hierarchy would apply to the benchmark firm when it stated:[2331]

> Indeed, if firms are unable to issue their own debt they may need to access funds from the more expensive bank debt market.

The key question is whether it is possible for the benchmark firm to entirely fund its notional debt requirement through the cheapest source of debt—the bond market. ACG also investigated this question, looking at the amount of debt raised through bonds by specific Australian electricity and gas network businesses, and concluded:[2332]

> The case for applying a bond market benchmark for the debt margin and a bond market benchmark for debt raising costs does not rest on 100% of the notional debt component necessarily being raised in the bond market. However, these examples illustrate it is a useful approximation, since utilities could, if they wished to raise all their debt in the bond market.

Finally, the AER notes that ACG estimated the costs of accessing bank debt at 7.9 to 9.3 bppa, instead of the 30 to 40 bppa proposed by Synergies.[2333] The difference is explained by ACG dealing with a more relevant sample set (Australian rather than US data), excluding debt sourced for inappropriate projects (principally mergers and acquisition activity, which the benchmark firm does not undertake) and using an appropriate statistical methodology (mean/median rather than inspection). Of course, since the benchmark is based on a form of debt with a lower total cost (including both cost of issuance and the interest on the debt itself), this difference is largely moot. However, it does put in context any argument that bank debt needs to be separately modelled, as there is relatively little difference between the costs for access to bank debt and the issuance costs of MTN.

The AER considers that Synergies' concerns on the appropriate debt form have been dealt with previously.[2334] The AER concludes that there is no reason to depart from its existing methodology, using the cost of issuing MTN as the benchmark for direct debt raising costs.

2329 The AER clarifies that 'cheapest debt' here refers to the total cost of the debt, not just the debt issuance costs. ACG, *Debt and equity raising costs*, December 2004, pp. 28–45.

2330 ACG, *Debt and equity raising transaction costs*, December 2004, pp. xiii–xix, 45.

2331 Synergies, *Debt and equity raising costs*, May 2009, p. 38.

2332 ACG, *Debt and equity raising costs*, December 2004, p. 37.

2333 ACG, *Debt and equity raising costs*, December 2004, table 5.10, p. 43; Synergies, *Debt and equity raising costs*, May 2009, pp. 35–36.

2334 ACG, *Debt and equity raising transaction costs*, December 2004, pp. 27–53.

Estimates from the QTC

Synergies stated that the administration charge levied by the Queensland Treasury Corporation (QTC) on government owned entities such as the Qld DNSPs for access to centrally-managed debt funding was a useful guide to the cost of raising debt.[2335] Synergies argued that the level of this charge—approximately 10 bppa—sets a floor for the relevant direct debt raising cost, given that the QTC captures significant economies of scale and operates as a not-for-profit entity.

The AER notes that the conceptual benchmark operates without any parent support (either government or non-government), so the costs of debt issuance via the QTC are irrelevant to benchmark debt raising costs. Synergies acknowledged this, but contended that it is not unreasonable to assume that the 10 bppa allowance reflected the actual costs of debt issuance. The AER considers that for this indirect argument to hold, there would need to be quantification of the degree to which the QTC varies from the benchmark firm, including:

- Economies of scale and scope available to the QTC but not the benchmark firm, which would need to be added to the 10 bppa. The AER notes that the QTC classifies the savings it achieves for customers in this manner:[2336]

  > On a positive note, QTC achieved quantifiable saving for customers and the state of $263 million (2007–2008: $164 million), principally related to our ability to add value through the management of borrowing margins.

  That is, the interest rate payable on QTC–issued government–backed debt would be lower than that payable if the firm issued as a stand alone entity. In this way, firms such as the Qld DNSPs actually have access to funds at less than the benchmark debt risk premium applied as part of the regulated weighted average cost of capital (WACC). However, there is not a prior theoretical reason to assume that a government organisation pays lower debt *issuance* costs, as opposed to debt risk premiums; particularly in comparison with a relatively large electricity network service provider.

- Clarification of the profit margin included in the administration fee *when undertaking transactions relevant to the benchmark firm*, which would need to be subtracted from the 10 bppa. The AER notes that the QTC booked a $43.2 million profit from capital market operations in 2008–09, so does not strictly speaking act entirely without profit.[2337] More critically, the allocation of costs within the QTC needs to be detailed, since it undertakes a range of debt funding while charging a flat administration fee. It is entirely plausible that large debt issuers (such as regulated electricity network service providers) are in fact cross–subsidising the smaller issuers to achieve a ‘no profit’ overall outcome.

- Quantification of the degree to which the government organisation underperforms against its private counterparts, which needs to be subtracted from the 10 bppa. There are sound economic reasons for believing that a government institution,

[2335] Synergies, *Debt and equity raising costs*, May 2009, p. 42.
[2336] QTC, *Annual Report 2008–09*, p. 4.
[2337] QTC, *Annual Report 2008–09*, p. 2.

constrained from offering market incentives to its management, may not be as efficient as the equivalent private sector organisation.

Given the lack of clarity on these adjustments, the AER considers that the QTC administration fee does not provide directly relevant evidence on the appropriate benchmark direct debt raising cost.

Status as a government owned entity

In its submission, the EUAA stated that the debt raising costs proposed by Energex seem unreasonable. The EUAA noted:[2338]

> Energex is owned by the Queensland Government, who arranges Energex's debt and provides Energex's equity. The AER should not allow any expenditure in this area unless there is clear demonstration that benefits will exceed costs.

The AER notes the point made by the EUAA regarding the reduction in debt raising costs for a government owned firm. Nonetheless, the debt raising allowance is not set based on the actual expenditure incurred by Energex (or any other specific DNSP). Consideration is given to the circumstances of the relevant DNSP,[2339] as well as the benchmark expenditure that would be incurred by an efficient DNSP.[2340] The AER also considers competitive neutrality principles for the treatment of government owned firms.[2341] The AER considers that an efficient firm may incur benchmark direct debt raising costs.

Estimates from academic research

There has been some consideration of the direct costs of raising debt in academic literature, and both consultant reports (by CEG and Synergies) referred to a paper by Lee, Lochhead, Ritter and Zhao.[2342] Synergies stated that the Lee et al. study supported a total up-front debt raising cost (including underwriting and other costs) of 2.19 per cent, based on the cost of issuing bonds between $200 and $500 million (US).[2343]

CEG stated that the Lee et al. study supported a total up-front debt raising cost (underwriting and other costs) of 1.47 per cent, based on the costs for utilities issuing

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2338 EUAA, *Submission to the AER*, August 2009, p. 20.

2339 NER, clause 6.5.6(c)(2) and 6.5.7(c)(2).

2340 NER, clause 6.5.6(e)(4) and 6.5.7(e)(4).

2341 AER, *Final decision, ACT DNSP*, 28 April 2009, p. 235.

2342 Lee, I., Lochhead, S., Ritter, J. and Zhao, Q., *The Costs of Raising Capital*, The Journal of Financial Research, Spring 1996, vol. 19(1), pp. 59–74.

2343 The total up-front cost of issuing capital is stated here to avoid consideration of the time value of money, since Synergies and the CEG treat this issue differently. Synergies, *Debt and equity raising costs*, May 2009, p. 41; citing Lee et al., *The Costs of Raising Capital*, Spring 1996, p. 62, table 1.

bonds;[2344] or an up-front cost of 0.94 per cent based on the cost of issuing investment-grade bonds.[2345]

The AER has previously discussed the limitations of the Lee et al. study in the context of equity raising costs.[2346] It is based on US firms raising capital (debt and equity) in the US market, which is several steps removed from the conditions of the benchmark firm, and is now more than fifteen years old.[2347] An additional concern specific to debt raising costs is the selection of bond types by Lee et al., with the inclusion of more complicated bond types such as serial and reset bonds (which are typically more complicated to issue), and the exclusion of shelf registered bond offerings (which now comprise a significant portion of the market).[2348]

Further, there are difficulties applying the data categories presented by Lee et al. to the conditions of the benchmark firm. The figures quoted by the CEG (bonds issued by utilities, and separately investment-grade bonds) are more relevant than the overall figure presented by Synergies (which includes bonds issued by non-utilities, and bonds below investment grade). However, the most relevant data categorisation (for regulatory purposes) is not presented by Lee et al.—the debt costs for a firm that is *both* a utility and issuing investment grade debt. Although investment grade bonds cost less than non-investment grade to issue, and utilities pay less than non-utilities to issue bonds, it is not possible to draw an empirically supported inference on the cost of investment grade bonds issued by a utility, relative to either category in isolation.

The adjustment by Synergies for ‘sensible funding practices’, whereby tranche size is adjusted by the company to minimise debt raising costs, has some theoretical support.[2349] There are initial economies of scale as costs invariant to issue size are spread across the debt value, and some plausible expectation of diseconomies of scale as tranche size increases.[2350] However, under the ACG approach the benchmark debt tranche size is set to be the median of observed domestic bonds over a five year rolling window, and maintaining the ACG approach therefore prevents the implementation of a debt issuance model that selects the size of the debt issue to minimise costs. At present the two methods arrive at the same end result, with the observed median issue size of $263 million (Australian) falling within the range of $200 million to $500 million (US) advocated by Synergies.[2351] Table L.1 shows the effect of selecting the Synergies tranche size on the two most relevant benchmarks from the Lee et al. study.

2344 The total up-front cost of issuing capital is stated here to avoid consideration of the time value of money, since Synergies and CEG treat this issue differently. CEG, *Debt and equity raising costs*, June 2009, p. 11. paragraphs 38–39; citing Lee et al., *The Costs of Raising Capital*, Spring 1996, p. 64, table 2.

2345 The total up-front cost of issuing capital is stated here to avoid consideration of the time value of money, since Synergies and CEG treat this issue differently. CEG, *Debt and equity raising costs*, June 2009, p. 11. paragraph 40; citing Lee et al., *The Costs of Raising Capital*, Spring 1996, p. 66, table 3.

2346 AER, *Final decision, ACT DNSP*, 28 April 2009, p. 250.

2347 Although published in 1996, the data is for the years 1990–1994. Lee et al., *The Costs of Raising Capital*, Spring 1996, p. 60.

2348 Lee et al., *The Costs of Raising Capital*, Spring 1996, pp. 60–61.

2349 Synergies, *Debt and equity raising costs*, May 2009, p. 41.

2350 Lee et al., *The Costs of Raising Capital*, Spring 1996, pp. 66–67.

2351 Details of the derivation of this median issue size are discussed below in this appendix.

Table L.1: Effect of bond size on direct debt costs in Lee et al. study

Lee et al. study	Total proceeds from bonds ($US million)	Sample size	Gross spread (% of total proceeds)	Other costs (% of total proceeds)	Total costs (% of total proceeds)
Investment Grade bonds (BBB– and up); includes bonds issued by utilities and non-utilities	0–9999 (no restrictions)	578	0.58	0.36	0.94
	200–500	60	0.50	0.43	0.93
Bonds issued by utilities; includes investment grade and non-investment grade bonds	0–9999 (no restrictions)	135	1.04	0.43	1.47
	200–500	16	1.00	0.40	1.40

Source: AER analysis of Lee, I., Lochhead, S., Ritter, J. and Zhao, Q., *The Costs of Raising Capital*, The Journal of Financial Research, Spring 1996, vol. 19(1), p. 64 (table 2) and p. 66 (table 3).

The AER notes that the selection of a $200 to $500 million (US) issue size slightly reduces the cost to a utility of raising debt, but has no material effect on the cost of issuing investment grade bonds.

Given the data limitations of the Lee et al. study, the AER considers that it is not relevant for the purposes of determining the benchmark debt raising cost for an Australian regulated utility issuing investment grade debt under prevailing market conditions.

Inclusion of corporate treasury costs

In its original report, ACG detailed six different types of direct raising costs expected to be incurred by a firm issuing MTN: underwriting fees, legal and roadshow expenses, company credit rating fees, issue credit rating fees, registry fees and paying fees.[2352] Synergies separately summarised the applicable cost categories used by ACG, and stated:[2353]

> It was not evident that these costs included the (substantial) costs associated with establishing and running a treasury operation…. If these costs have not been included, this estimate will understate the costs of a firm issuing its own debt.

Synergies described the 'corporate treasury' functions as being the ongoing monitoring and management of the bond issue, including the appropriate systems to manage risk, allow settlement and payments (for example, Austraclear, Euroclear), and provide financial market information (for example, Bloomberg, Reuters). Synergies did not present any quantification of these treasury operation costs, nor any analysis of whether these costs are included within forecast opex.[2354]

[2352] ACG, *Debt and equity raising costs*, December 2004, pp. 51–52; see also the description for domestic bond issues on pp. 37–38.
[2353] Synergies, *Debt and equity raising costs*, May 2009, p. 41.
[2354] Synergies, *Debt and equity raising costs*, May 2009, pp. 37–39.

The AER observes that ACG does not separately indentify a cost category relating to treasury operation. It is not clear if this is because ACG:

- considered that the functions were already included in other cost categories
- considered that there was not a need for these specific activities
- considered that these functions, while required, did not constitute a material expense sufficient to require identification
- failed to consider the need for these functions at all.

Obviously, only the fourth of these options would constitute a valid reason for the addition of another cost category to the ACG methodology.

The AER notes the exhaustive nature of the ACG review, which included an extensive brief:[2355]

> The first requirement was to gather comprehensive information about institutional and other aspects of the capital issuance process (both debt and equity) by Australian companies, with particular reference to infrastructure companies.

ACG analysed the entire process of capital raising, reviewed academic research, investigated regulatory practice and interviewed market participants; including bankers, investment bankers, market analysts and stockbrokers.[2356] Given the depth and breadth of the ACG review, the AER does not consider it likely that ACG failed to consider the need for these functions. While no definitive statement can be made by the AER about which of the first three options is correct, in each case the benchmark efficient firm would not be under-compensated. Further, the AER considers that there is a need for rigorous examination in this area to avoid double counting, given that similar functions are already assumed to be part of general operational expenses (particularly information technology costs, including the provision of financial market information and front/back office monitoring systems).

The AER considers that the breakdown of cost categories by ACG provides the most appropriate framework for determination of direct debt raising costs.

Sample selection for the ACG methodology

CEG stated that the selection of bonds in the AER's 2008 update of the ACG methodology was flawed, on three grounds:

- Requirement for a five year rolling window.[2357] The ACG methodology included this statement: [2358]

> The median rolling 5 year gross underwriting fee is calculated for each tenor group on the basis of the adjusted bppa fees.

[2355] ACG, *Debt and equity raising costs*, December 2004, p. 1.
[2356] ACG, *Debt and equity raising costs*, December 2004, p. vi
[2357] CEG, *Debt and equity raising costs*, June 2009, p. 7, paragraph 24.
[2358] ACG, *Debt and equity raising costs*, December 2004, p. 49.

CEG located bonds older than five years (at the time of the update) in the AER data set. Hence, the AER update included bonds that should have been excluded.

- Bloomberg filtering criteria. The ACG methodology included this statement:[2359]

  > The data base is all Australian companies (excluding GBEs and banks) issuing bonds (excluding convertible bonds) with gross underwriting fees reported by Bloomberg.

  By applying this filter to Bloomberg, CEG located additional bonds that were not listed by the AER update. Hence, the AER update excluded bonds that it should have included.

- Exclusion of 'non-live' bonds. CEG noted that two bonds listed by the AER had matured. Hence, the AER update included bonds that it should have excluded.

Excluding the older bonds (by applying the five year rolling window) reduces the AER sample set from 34 bonds to 11; excluding the two expired bonds lowers it further to 9, but the 21 additional bonds (found by CEG using Bloomberg) increase the data set to 30 bonds.[2360] CEG stated that this data set, rather than the AER data set, was the appropriate basis for an assessment of the benchmark direct debt underwriting costs based on the ACG methodology. Table L.2 shows the effect of this change on the total upfront gross underwriting spread.[2361]

Table L.2: Total gross underwriting spread (up front)

Data set	Tenor group	Number of bonds	Gross underwriting costs (% of total proceeds)	
			Mean	Median
AER data set	5 year	17	0.28	0.30
	10 year	17	0.45	0.40
	Combined	**34**	**0.37**	**0.36**
CEG data set	5 year	19	1.60	1.38
	10 year	11	0.89	0.45
	Combined	**30**	**1.34**	**0.82**

Source: CEG, *Debt and equity raising costs*, June 2009, p. 35–36, table 8; AER analysis of Bloomberg.

2359 CEG, *Debt and equity raising costs*, June 2009, p. 7, paragraph 24; citing ACG, *Debt and equity raising costs*, December 2004, p. 49.

2360 The resulting CEG data set is appended to the CEG report; note that paragraph 134 (p. 34) states there were 23 bond issues not reported by the AER, but the CEG table shows only 21 such bonds. CEG, *Debt and equity raising costs*, June 2009, p. 34–37, appendix A.

2361 Figures are presented in this manner to separate issues regarding the sample set construction from issues related to the time value of money, which are discussed below.

As can be seen from table L.2, the change to the data set makes a large difference to the cost of raising debt, lifting the median gross underwriting spread for the full sample by half a percentage point, from 0.36 to 0.82 per cent of the total proceeds of the debt issue.[2362] The AER notes the CEG data set has a higher cost of debt issuance for five year tenors than for ten year tenors.

The AER confirms that it continues to implement the ACG approach, including the selection of bonds in accordance with the ACG criteria specified in the 2004 report. However, the AER does not mechanistically apply the selection procedure without regard to the underlying characteristics of each individual bond. That is, the AER checks the bonds to ensure that they meet the requirements expressed in the ACG report, including that the bond is:

- issued by an Australian company that is not a bank, finance company, insurer or government entity[2363]
- straight debt, excluding all combined debt/equity issues, convertible bonds and other hybrid securities[2364]
- reported with a valid gross underwriting fee, excluding any bond where the fee given by Bloomberg is does not match the relevant debt offer documentation and/or annual report.[2365]

Further, the AER has searched for the specific additional bonds identified by CEG, but is unable to locate a number of the new bonds listed by CEG, as shown in table L.3.

Table L.3: Bonds identified by CEG but not located by the AER

Bonds	Type	Amount ($ million)	Announcement date	Maturity date
Toyota Finance Australia	Euro MTN	300	20/4/2006	9/5/2011
Leighton Finance	Euro-dollar	110	9/5/2006	16/5/2011
Myer Group Finance Ltd	Australian	255	1/8/2006	15/3/2013
Toyota Finance Australia	Euro MTN	200	15/5/2007	31/5/2010
Toyota Finance Australia	Euro MTN	250	5/3/2008	19/3/2012
Toyota Finance Australia	Euro MTN	100	8/7/2008	28/7/2011

Source: CEG, *Debt and equity raising costs*, June 2009, p. 35–36, table 7.

[2362] The median is preferable to the mean for these small skewed samples.
[2363] As per the database description (step 1) at ACG, *Debt and equity raising costs*, December 2004, p. 49.
[2364] As per the separation of convertible debt at ACG, *Debt and equity raising costs*, December 2004, p. 46–47.
[2365] As per the methodology at ACG, *Debt and equity raising costs*, December 2004, p. 49.

The AER has attempted to determine the reason for the discrepancy between CEG's results and its own investigations. Correspondence with Bloomberg has been unable to resolve the main cause of the discrepency, though it has proved helpful in clarifying the status of individual bonds. One possible explanation is that the additional bonds may not be listed in the official LEAG tables (which detail underwriting costs) presented by Bloomberg. Although a particular table presentation is not relevant for the purposes of establishing a debt raising cost benchmark, the criteria for inclusion of bonds in the LEAG tables align with the ACG criteria.

One example deals with the Toyota Finance Australia Limited (TFA) bonds listed in table L.3. Bloomberg indicated that there are significant 'country of risk' issues with these bonds—that is, they are excluded from the LEAG tables because although there is a notional Australian company involved (TFA), the true substance of the bonds reflects an international issuer.[2366] TFA is a wholly owned subsidiary of Toyota Financial Services Corporation, which itself is a subsidiary of Toyota Motor Corporation.[2367] Both parents are Japanese companies, and Bloomberg considered that the TFA bonds actually reflect the global financing activities of the entire organisation, not specifically the Australian subsidiary company. The AER considers that the documentation for more recent Toyota debt issues formalises this international arrangement.[2368] The AER notes that international issuers are excluded by the ACG criteria, so in this case the bonds should not be included in the data set.

Further, the AER understands that bonds without recent trading data may not be reported by Bloomberg. Therefore, if bonds are relatively illiquid, it may be that they are presented by Bloomberg at one date and not another, dependent upon the trading pattern of the bond.

Nonetheless, the AER considers it inappropriate to include these bonds without validation of their issuance costs and term, or a fuller understanding of the reason they do not appear in Bloomberg during the AER investigation process.

On a related issue, the AER considers that there that there are concerns with the inclusion of bonds issued by Fortescue Metals Group (FMG) Finance in the data set. These additional bonds, as reported by CEG, are listed in table L.4.

2366 The AER notes the LEAG eligibility criteria principally focus on comparing the performance of underwriters such as the total number of deals executed by them rather than comparing the characteristics of bonds. In this context, country of risk does not refer to sovereign risk in respect of the issuer's domicile but rather which national cohort of underwriters are the appropriate competitors for executing the deal.

2367 Toyota Motor Corporation, *Consolidated Financial Summary, April 1, 2006 through March 31, 2007*, May 2007 (English translation from the original Japanese-language document).

2368 Toyota Motor Finance (Netherlands) BV, Toyota Credit Canada Inc, Toyota Finance Australia Limited and Toyota Motor Credit Corporation, *Supplementary prospectus: Euro medium term note programme*, 19 December 2008.

Table L.4: FMG bonds identified by CEG, but excluded by the AER

Bonds	Type	Amount ($ million)	Announcement date	Maturity date
FMG Finance Ltd	Euro-dollar	250	11/8/2006	1/9/2011
FMG Finance Ltd	Private placement	250	11/8/2006	1/9/2011
FMG Finance Ltd	Private placement	315	11/8/2006	1/9/2013
FMG Finance Ltd	Euro non-dollar	315	11/8/2006	1/9/2013
FMG Finance Ltd	Euro-dollar	320	11/8/2006	1/9/2013
FMG Finance Ltd	Private placement	320	11/8/2006	1/9/2013
FMG Finance Ltd	Euro-dollar	1080	11/8/2006	1/9/2016
FMG Finance Ltd	Private placement	1080	11/8/2006	1/9/2016

Source: CEG, *Debt and equity raising costs*, June 2009, p. 35–36, table 7; AER analysis of Bloomberg.

As shown in table L.4, CEG included eight bonds issued by FMG Finance on 11 August 2006. Inspection of the prospectus for this bond issuance reveals that key details of this capital raising are incorrect as reported by CEG (based on the Bloomberg data service).[2369] There were four types of senior secured notes issued, but each is reported twice by CEG, and in one case the amount raised misreports Euros as US dollars.[2370] More fundamentally, the debt issuance occurs in conjunction with a $US300 million equity issuance (and associated $100 million placement of unsecured subordinated notes).[2371] The AER notes that the ACG methodology is based on straight debt transactions not combined equity and debt raising costs. An underwriting spread of 2.77 per cent is quoted by CEG (based on Bloomberg) for all eight bonds. This figure includes the costs of issuing equity and debt, as well as legal and other fees that do not come under the underwriting spread in the ACG methodology.[2372] Further, the aggregate nature of this single-figure reporting renders it impossible to account for the time value of money (as will be discussed later in this appendix) since the term of the bonds range between five and ten years.

2369 FMG Finance Pty Ltd, *Offering memorandum: Senior secured notes*, 11 August 2006; lodged with the ASX on 14 August 2006.

2370 The AER notes that CEG include a presentation of data with repeated issues excluded; i.e. where they remove five of the erroneously recorded FMG bonds from the Bloomberg data set. It is not clear why CEG chose to present this calculation, but the AER considers that duplication may have occurred because of the issuance procedure adopted by Citigroup, see FMG Finance, *Offering memorandum*, August 2006, pp. 2, 19.

2371 FMG Finance, *Offering memorandum*, August 2006.

2372 The financing related costs reported in the prospectus include stamp duty, financial advisory, legal and underwriting associated with the Leucadia transactions, the offering of the Senior secured notes and the operating leases; see FMG Finance, *Offering memorandum*, August 2006, p. 40 and following.

The AER considers that the eight FMG Finance bonds fail to meet the ACG criteria for being straight debt issuance and reporting valid gross underwriting fees. As such, the AER considers that none of these bonds should be included in the data set.

This leaves seven bonds that the AER has added to its data set, listed in table L.5.

Table L.5: Bonds identified by CEG and added to the AER dataset

Bonds	Type	Amount ($ million)	Announcement date	Maturity date
FBG Finance Ltd	Private placement	700	21/6/2005	15/6/2015
FBG Finance Ltd	Private placement	300	21/6/2005	15/6/2035
Telstra Corp Ltd	Euro MTN	250	3/9/2008	9/10/2012
BHP Billiton Fin USA Ltd	Global	1500	18/3/2009	1/4/2014
BHP Billiton Fin USA Ltd	Global	1750	18/3/2009	1/4/2019
Rio Tinto Fin USA Ltd	Global	2000	14/4/2009	1/5/2014
Rio Tinto Fin USA	Global	1500	14/4/2009	1/5/2019

Source: CEG, *Debt and equity raising costs*, June 2009, p. 35–36, table 7; AER analysis of Bloomberg.

CEG included two bonds issued by Fosters Brewing Group (FBG) Finance on 21 June 2005, as shown in table L.5. Although these bonds meet the criteria for inclusion, the AER notes that one has a tenor of 30 years, and so is of relatively little value when estimating the issuance costs of a MTN with a tenor of between five and ten years. The AER notes that the longest bond previously accepted into the ACG data set was 20 years, so a consistency case could be made for the exclusion of this bond. However, since the ACG methodology does not clearly specify an upper limit for the length of term of a MTN, the AER considers that on balance both these bonds should be included.

CEG also includes five bonds that have been issued since the most recent AER update of the ACG methodology (in mid 2008). This includes bonds issued by Telstra (3 September 2008), BHP Billiton (two bonds on 18 March 2009) and Rio Tinto (two bonds on 14 April 2009). These five bonds have been included in the current data set.

Finally, there are two bonds that were in the original AER data set, but were excluded by CEG. These are shown in table L.6.

Table L.6: Bonds excluded by CEG but remaining in the AER data set

Bonds	Type	Amount ($ million)	Announcement date	Maturity date
Telstra Corp Ltd	Euro MTN	334	16/3/2005	1/4/2013
BHP Billiton Fin USA Ltd	US domestic	926	26/3/2007	29/3/2009

Source: CEG, *Debt and equity raising costs*, June 2009, p. 37, table 8; Bloomberg.

CEG excluded a bond issued by BHP Billiton on 26 March 2007 because it had a maturity of two years and had therefore already matured at the time of its assessment. The AER observes that the ACG methodology uses a five year rolling window, but that this does not necessarily exclude bonds issued within this window that have already reached maturity. The AER considers that the ACG methodology is not primarily concerned with the inclusion of 'live' bonds, since bonds with a tenor longer than five years are excluded from the rolling window once five years have passed, despite the fact that they have not yet matured. Accordingly, the AER considers that consistent with the ACG methodology, this bond should be retained in the data set until the announcement date reaches five years from the sampling date.

CEG excluded an additional bond issued by Telstra on 16 March 2005, which was included in the AER data set. The AER can find no reason why this bond has been excluded, and has clarified with Bloomberg that the bond is correctly reported. The AER considers that it meets the ACG criteria and has not removed it from the data set.

The effect of the changes to the data set, including the exclusion of bonds outside the five year window, the inclusion of bonds identified by CEG and the addition of data up to April 2009 is shown in table L.7.

Table L.7: Total gross underwriting spread (up front)

Data set	Tenor group	Number of bonds	Gross underwriting costs (% of total proceeds)	
			Mean	Median
April 2009 data set	5 year	17	0.28	0.30
	10 year	17	0.45	0.40
	Combined	**34**	**0.37**	**0.36**
Revised data set	5 year	8	0.37	0.35
	10 year	8	0.40	0.45
	Combined	**16**	**0.39**	**0.36**

Source: AER analysis of Bloomberg data.

The AER observes that there is little overall impact on the pattern of debt raising costs after the update. For bonds with a tenor around five years, both the mean (from 0.28 to 0.37 per cent) and median (0.30 to 0.35 per cent) have increased slightly. For bonds with a tenor around ten years, the mean has decreased slightly (from 0.45 to 0.40 per cent) but the median has increased slightly (from 0.40 to 0.45 per cent). For the overall group, the mean has increased (from 0.37 to 0.39 per cent) but the median remains unchanged (at 0.36 per cent).

The AER considers that the revised data set is the most appropriate proxy for estimating the gross underwriting spread in respect of a benchmark direct debt raising cost.

Inflation

In its report, CEG stated that the current debt issuance methodology adopted by the AER systematically under compensates service providers because it fails to take into consideration inflation.[2373] CEG observed that the non-underwriting direct costs used by the AER to estimate the direct cost of debt were the same figures prepared by ACG in 2004, and considered that these costs should be increased for inflation.[2374] The AER had previously argued that there was no need to inflate these direct costs because the benchmark was expressed as a percentage; and although the costs would increase with inflation (the numerator) so too would the total debt raised (the denominator) such that the benchmark percentage is left unchanged by inflation.[2375] In its latest report, CEG acknowledged this logic, but noted that the AER increased the benchmark debt issue size from $175 million (as determined by ACG in 2004) to $200 million (based on updated data). CEG calculated that this increased the denominator for each debt issue by 14.2 per cent without a corresponding increase in the numerator (nominal costs per issue), in effect deflating the benchmark debt raising costs.[2376] On this basis, CEG stated that the non-underwriting costs should be indexed by 11.0 per cent, based on the increase in the financial and insurance services price index between 2004 and 2009.[2377]

The AER considers that care should be taken not to confuse the total debt raised (which is indexed every year as the RAB increases) with the debt issue size (which was increased once, from $175 million to $200 million). Issue size is not the relevant denominator for all debt raising costs; in fact most of the benchmark costs are unaffected by the size of the bond issue. For example, consider the cost of company credit rating, which is incurred as a fixed cost per annum. Increasing the issue size (but holding the RAB constant) results in the credit rating being spread across fewer bond issues, increasing the cost per bond issue. However, each bond issue is now larger, exactly offsetting the increased costs such that the costs per dollar of total debt raised remain the same.

It is only those specific costs that are set *as a fixed cost per bond issue* that are actually deflated in the manner described by CEG. Specifically, this is the legal/roadshow fee and the registry fee. The AER has reflected on the increase in the debt issue size to $200 million and notes that the update occurred as a result of the strict application of the ACG methodology. The ACG methodology determines the benchmark bond issue size on the basis of the median domestic bond size observed using a rolling five year window, and the update of bonds (in 2006) resulted in the median moving upward.[2378] This was not an explicit adjustment for inflation; but it cannot be inferred that inflation played no role in the median moving upward. However, given that the ACG methodology made no allowance for similar updates of fixed costs, and that leads to a deflation effect, the AER has decided to refine its approach based on the ACG methodology. The AER considers that the most appropriate resolution is to increase the relevant cost components from the ACG

[2373] CEG, *Debt and equity raising costs*, June 2009, paragraph 33, pp. 9–10.
[2374] CEG, *Debt and equity raising costs*, June 2009, paragraph 37, p. 10.
[2375] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 231.
[2376] CEG, *Debt and equity raising costs*, June 2009, paragraphs 35–36, p. 10.
[2377] CEG, *Debt and equity raising costs*, June 2009, paragraph 37, p. 10.
[2378] ACG, *Debt and equity raising costs*, December 2004, p. 45.

methodology (legal/roadshow fees and registry fees) to ensure that the DNSPs are not under-compensated.

The AER has contacted Standard and Poor’s to update credit rating fees. Standard and Poor’s indicated:[2379]

> Whilst we use our standard fees as a guide in setting fees, there are many factors that are taken into consideration such as ownership structure, size and complexity of the entity etc.
>
> The standard initial issuer credit rating fee for an Australian corporate is set at A$70,000. Thereafter, analytical surveillance is maintained and a surveillance fee, currently set at A$50,000 is levied on the anniversary of the initial rating date. Standard & Poor's considers the characteristics of each individual entity when setting fees, and arrangements can and do vary from the standard fees.
>
> The current standard credit rating fee for a long term (maturity over 12 month) corporate bond is 4 basis points.

The AER notes that all benchmark firms are ongoing debt issuers, so the benchmark company credit rating fee should be set at $50 000 per annum. Additionally, the AER will update the issue credit rating fee from 3.5 basis points to 4 basis points.

The AER also attempted to update the legal/roadshow fees and registry fees by contacting relevant organisations. However, responses were sparse and there was no clear way to ensure an authoritative answer. As a result, the AER has increased these values by the 15.1 per cent consumer price index change between September 2004 and September 2009.[2380] The AER considers it more appropriate to use this general inflation measure instead of the more specific financial and insurance services price index as proposed by CEG.[2381] The AER has rounded values where appropriate, and applied a materiality threshold to the paying fees.

The median domestic bond issue size has also been updated, based on the ACG methodology.[2382] This involves a five–year rolling window of Bloomberg-reported domestic MTN, filtered to include infrastructure companies.[2383] This update increases the median from $200 million to $263 million. The AER notes that this is a conservative estimate, since bonds issued on the same day but with different tenors have been included separately. It is entirely plausible that these bonds are issued jointly, effectively constituting one larger bond issue.

The resulting updates to the ACG values are summarised in table L.8.

2379 Standard and Poor’s, email re: Credit rating information, 30 October 2009.

2380 This is calculated as the change in CPI (weighted average of eight capital cities across all groups) from September 2004 to September 2009; see www.abs.gov.au.

2381 The AER notes that the financial and insurance services index is a recent addition and has exhibited high volatility; see CEG, *Debt and equity raising costs*, June 2009, paragraph 37, p. 11.

2382 ACG, *Debt and equity raising costs*, December 2004, pp. 39, 49–50, 52.

2383 The Australian infrastructure companies with bonds currently included in the data set are Alinta Network Holdings, Australia Pacific Airports Melbourne, Brisbane Airport Corporation, DBNGP Finance, Energy Partnership Gas, Envestra, ETSA Utilities Finance, Origin Energy, Santos Finance, Sydney Airport Finance and Westralia Airports.

Table L.8: Updated values for the ACG debt raising methodology

Category	Previous value and basis	Update method	New value and basis
Legal and roadshow	$100 000 up front per issue (range $80 000 to $100 000 per annum)	CPI	$115 000 up front per issue
Company credit rating	$50 000 per annum (range $30 000 to $50 000 per annum)	Issuer information	$50 000 per annum (ongoing issuers)
Issue credit rating	3.5 basis points up front per issue	Issuer information	4 basis points up front per issue
Registry fees	$3 000 up front per issue	CPI	$3 500 up front per issue
Paying fees	$4/$1million per annum	Below materiality threshold	$4/$1million per annum
Median bond size	$200 million	Rolling 5 year window	$263 million

Source: ACG, *Debt and equity raising costs*, December 2004; Standard and Poor's, email re: Credit rating information, 30 October 2009; Bloomberg; AER analysis.

The AER notes that several features of the debt raising cost methodology provide the DNSPs with at least an efficient benchmark cost. Where ACG presented a range, the AER has been conservative and applied the upper boundary of this range. For the updated credit rating fees, combining a current estimate of fixed costs with a median bond issue size based on the last five years of data will maintain compensation at the upper end of the efficient cost range. In effect, this combines an up to date numerator with a denominator deflated by two and a half years of inflation. However, the AER considers that the overall effect of this estimation will be small, and is acceptable in order to ensure that the efficient service provider is provided the opportunity to recover at least the efficient costs of providing standard control services.

Amortisation

In its report, CEG stated that the current debt issuance methodology adopted by the AER systematically under compensates service providers because it fails to take into consideration the time value of money when there is delayed recovery of an upfront payment.[2384]

The AER, following the ACG methodology and consistent with previous determinations, divided total debt issuance costs by the debt maturity to obtain an annual allowance in its most recent regulatory determination.[2385] In applying this methodology, the AER rejected arguments from CEG on the need for amortisation.[2386] Although the AER observed that it was theoretically correct to adjust

[2384] CEG, *Debt and equity raising costs*, June 2009. pp. 13–14.

[2385] Alternatively, this can be conceptualised as amortisation where the discount rate is set at zero. AER, *Final decision, ACT DNSP*, 28 April 2009, pp. 230–231.

[2386] Further, the amortisation issue was not presented in any of the initial regulatory proposals and, when presented as part of the NSPs' revised proposals, did not occur in response to a matter for the time value of money when upfront costs were repaid over time, it stated that:[2387]

> The amortised cost of ten year debt issuance costs would provide a lower allowance than the simple division of five year debt issuance costs.

That is, the AER noted the limitations of the ACG approach (simple division of five year debt issuance costs), but as the service provider was recovering at least its efficient costs there was no requirement to add further complexity in this area.

In its latest report, CEG stated that simple division did not produce the best estimate of debt raising costs taking account of the time value of money.[2388] To demonstrate the scale of impact, CEG provided an illustrative example where discounting of cash flows increases the annual cost of raising debt by fifty per cent.[2389] Further, CEG re-calculated the figures used by the AER in the April 2009 final decisions (using a discount rate of 9.6 per cent, based on an indicative nominal vanilla WACC) and concluded that:[2390]

> The AER's contention that using simple division is 'conservative' relative to amortising underwriting costs over 10 years is incorrect. I consider that given the significant differences in outcomes between simple averaging and amortisation, and the superiority of the latter method, it is not reasonable to rely upon simple averaging to estimate direct debt raising costs.

The AER considers that CEG has not accurately stated the AER's position in its April 2009 final decisions. The AER explicitly acknowledged its preference for discounting the time value of money as a general rule.[2391] The AER's statement that the established methodology (simple division of five year costs) produces a better outcome for the business than the alternative (amortisation of ten year costs) was made on the basis of the conditions relevant to the businesses at the time. The amortisation calculation is clearly dependent on the discount rate selected, and CEG arrives at a higher value under the amortisation approach as a direct result of selecting a high discount rate (9.6 per cent). The AER notes that the nominal vanilla WACC applied in the April 2009 final decisions was approximately 8.8 per cent.[2392]

CEG justified the selection of a nominal discount rate as follows:[2393]

> The nominal cost of capital is appropriate for spreading underwriting costs over time. The nominal rate should be applied because the underlying calculation seeks to find a constant nominal stream of payments over the term of the bond that is equivalent in present value to the upfront underwriting costs.

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addressed in the draft decision. The AER was not required to consider such issues, but chose to undertake a review of the NSP's proposed variation on that occasion.

2387 AER, *Final decision, ACT DNSP*, 28 April 2009, p. 230.
2388 CEG, *Debt and equity raising costs*, June 2009, p. 5.
2389 CEG, *Debt and equity raising costs*, June 2009, p. 5, paragraph 17.
2390 CEG, *Debt and equity raising costs*, June 2009, p. 6, paragraph 19.
2391 AER, *Final decision, ACT DNSP*, 28 April 2009.
2392 The final nominal vanilla WACCs were in the range 8.78 to 8.83 per cent. One example is AER, *Final decision, ACT DNSP*, 28 April 2009, p. xxi.
2393 CEG, *Debt and equity raising costs*, June 2009, p. 5, paragraph 18.

The AER notes that the choice of discount rate determines whether the amortised 10 year debt raising costs are higher or lower than the simple division of five year costs. The median gross underwriting fees (based on revised data set) are now higher for both five year tenor bonds (35 basis points) and ten year tenor bonds (45 basis points) than those adopted in the April 2009 final decisions. Table L.9 shows the effect, relative to the simple division of five year costs, of discounting the 10 year upfront costs at:

- 9.60 per cent (based on the CEG report figure)
- 8.96 per cent
- 8.79 per cent (based on the ActewAGL April 2009 final decision).

Table L.9: Effect of discount rate on the current bond sample set

Data set	Tenor group	Discounting behaviour	Median gross underwriting costs (basis points)	Basis points per annum (bppa)
Revised data set	5 year	Simple division	35	7.0
	10 year	Discount at 9.60%	45	7.2
	10 year	Discount at 8.96%	45	7.0
	10 year	Discount at 8.79%	45	6.9

Source: AER analysis of Bloomberg data.

The AER observes that, given the current values for upfront underwriting costs, the break even point occurs at 8.96 per cent. That is, if the nominal vanilla WACC is less than 8.96 per cent, the ACG approach will provide sufficient funds. For comparison, the nominal vanilla WACCs in the DNSPs' regulatory proposals are between 9.49 and 9.52 per cent. If market conditions remain such that the nominal vanilla WACC is above 8.96 per cent at the time of the final decision, then the ACG simple division approach will under compensate the service provider relative to the amortisation approach. Additionally, if the amounts for upfront gross underwriting change across time (particularly if the cost for the five year tenor group decreases, or the cost for the ten year tenor group increases) this could also lead to under compensation.

The AER considers that, although the ACG approach is simple and relatively accurate, it has been shown that could under compensate the service provider in certain circumstances.

Having considered the issues raised and the operation of the PTRM which multiplies the benchmark debt raising cost allowance in basis points per annum by the notional nominal debt amount each year, the AER has amortised the upfront costs of debt raising costs over ten years at the nominal vanilla WACC relevant to each business for this draft decision. This refined approach is to be used for future regulatory decisions requiring benchmark debt raising cost allowances.

For cost categories under the ACG approach other than underwriting spread, amortisation is required if the cost is incurred as a one off at the commencement of the regulatory control period, but not for those costs incurred on an annual basis. This means that legal and roadshow fees, issue credit rating and registry fees will all need to be amortised at the relevant discount rate.

Finally, a decision must be made on the appropriate bond length for amortisation. The debt risk premium is set on a 10 year bond, so first order consistency would require that the benchmark debt raising costs be amortised over 10 years to match the term of this bond.

The AER noted in the WACC review:[2394]

> On average the benchmark efficient energy network business refinances its debt portfolio every 10 years, implying that the current allowed debt-raising costs (which assume a five-year refinancing period) are excessive.

Synergies noted this statement, and stated:[2395]

> However, these estimates [debt raising costs] have always been applied within the context of a ten year risk–free rate.

That is, the ACG methodology sets the debt raising cost allowance based upon a bond with five year tenor even while explicitly recognising that the risk–free rate and debt risk premium are determined based on a ten year term.[2396] On this basis, Synergies argued that there are no grounds to move away from the five year tenor for the purposes of debt raising costs.[2397]

The AER considers that this argument overlooks that the ACG recommendation of a ‘conservative’ five year tenor was explicitly linked to the simple division of upfront costs (for example the adoption of zero cost of capital which ignores time value of money).[2398] Since the CEG report demonstrated that the ACG methodology in this particular area does not produce an acceptable outcome (for example, there exists a potential for under compensation), it would be inappropriate for the AER to maintain the five year assumption. Accordingly, the AER adopts a ten year term for debt raising cost purposes, consistent with the ten year term for a benchmark bond. To allow the maximum collection of data, each bond in the ACG ten year tenor group (which includes bonds of between eight and twelve years tenor) will be amortised on its particular term to produce a cost estimate in basis points per annum, before aggregation of the data to take the median value.

AER conclusion on direct debt raising costs

After these adjustments to the selection of bonds, the indexing of deflated fixed costs, and the inclusion of amortisation (based on a nominal vanilla WACC of 10.04 per cent), the indicative direct debt raising costs are shown in table L.10. The appropriate WACC (to be incorporated in the amortisation calculation) will be

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[2394] AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 167.
[2395] Synergies, *Debt and equity raising costs*, May 2009, p. 40.
[2396] ACG, *Debt and equity raising costs*, December 2004, pp. 49–50.
[2397] Synergies, *Debt and equity raising costs*, May 2009, p. 40.
[2398] ACG, *Debt and equity raising costs*, December 2004, p. 49.

updated for the final decision (in keeping with the averaging period adopted for each of the DNSPs).

Table L.10: Indicative direct debt raising costs with a nominal vanilla WACC of 10.04 per cent

Fee	Explanation	1 Issue	3 Issues	7 Issues	17 Issues	18 Issues
Amount Raised	Multiples of median MTN ($263m)	$263m	$789m	$1841m	$4471m	$4734m
Gross under-writing fee	Median gross underwriting spread, upfront per issue	7.34	7.34	7.34	7.34	7.34
Legal and roadshow	$115k upfront per issue	0.71	0.71	0.71	0.71	0.71
Company credit rating	$50k per annum	1.90	0.63	0.27	0.11	0.11
Issue credit rating	4 basis points up front per issue	0.65	0.65	0.65	0.65	0.65
Registry fees	$3.5k up front per issue	0.13	0.13	0.13	0.13	0.13
Paying fees	$4/$1million per annum	0.01	0.01	0.01	0.01	0.01
Total	**Basis points per annum**	**10.7**	**9.5**	**9.1**	**9.0**	**9.0**
Previous value (2008 update)	Number of $200m issues	1 issue	4 issues	9 issues	22 issues	24 issues
	Basis points per annum	10.4	8.5	8.1	8.0	8.0

Source: ACG, Bloomberg, AER analysis.
Note: The nominal vanilla WACC of 10.04 per cent is used to produce the indicative table because it is the average of the value for the ETSA Utilities draft decision (10.02 per cent) and the value for the Qld DNSPs draft decision (10.06 per cent). For each business, the calculation should be carried out with the relevant nominal vanilla WACC.

L.5 AER conclusion

The AER has considered the arguments put forward by the DNSPs on benchmark debt raising costs, including consultant reports and all relevant submissions.

The AER considers that there is no basis for an allowance for the indirect costs of debt raising. If indirect costs do in fact occur in practice, the current methodology of providing an allowance for the cost of debt would include compensation as part of the debt yield. Providing a separate compensation would result in double counting and be inconsistent with the regulatory framework.

The AER considers that MTN issuance costs are the appropriate proxy for direct debt raising costs incurred by the benchmark firm (based on the ACG methodology). The AER considers that the ACG methodology for assessing the total direct costs of debt (including underwriting spreads and other transactions costs) produces the best estimate possible, principally because none of the proposed alternative methodologies closely match the circumstances of the benchmark firm. The AER has updated its selection of bonds from the Bloomberg data service to fully align with the ACG methodology.

The AER considers that simple division of up-front costs (as per the ACG methodology) could result in under compensation for the benchmark firm under certain circumstances. Accordingly, the AER refines the ACG methodology to allow for the amortisation of fixed up-front costs at the appropriate discount rate. Further, the AER has accounted for inflation effects on the individual components of debt raising costs.

The direct debt raising cost allowance for each firm will be dependent on the number of standard sized debt issues required by each DNSP (based on the debt value of the RAB), and the nominal vanilla WACC applying to each DNSP (to be incorporated in the amortisation calculation). The allowance, expressed in bppa as an input to the PTRM, is applied to the debt portion of each DNSPs' RAB for each year of the next regulatory control period to determine the benchmark debt raising costs included in the opex forecast.

M. Benchmark equity raising costs

M.1 Introduction

Equity raising costs, such as legal fees, marketing costs and other transactions costs, are incurred in raising new equity capital. These are upfront expenses, with little or no ongoing costs over the life of the equity. While the majority of the equity a firm will raise is typically obtained at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of capital, and accordingly may incur equity raising costs.

The AER has accepted that equity raising costs for new issuance are a legitimate cost for a benchmark efficient firm only where external equity funding is the least cost option available.[2399] A DNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for example, retained earnings—are insufficient, subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

The AER concurrently assessed the regulatory proposals of three DNSPs:

- Energex and Ergon Energy (the Qld DNSPs)
- ETSA Utilities.

M.2 Regulatory requirements

Although these regulatory proposals are assessed under two separate decisions, the consideration of appropriate benchmark equity raising costs is a common matter.

The revenue and pricing principles set out that each DNSP should be provided with a reasonable opportunity to recover at least its efficient costs.[2400] It is also pertinent that regard should be had to the potential for under or over investment, a matter that may be materially impacted by equity raising costs.[2401] The opex criteria (or capex criteria as the case may be) require that the total of the forecast opex (or capex) reasonably reflects the efficient costs and the costs that a prudent operator in the circumstances of the relevant DNSP would require.[2402] Further, the forecast opex (or capex as the case may be) is assessed with regard to the benchmark opex (or capex) that would be incurred by an efficient DNSP over the regulatory control period.[2403]

[2399] AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, p. 100; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, p. 144 and AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, p. 88.

[2400] For electricity, this means efficient costs associated with direct control network services and regulatory obligations; see NEL, section 7A.

[2401] NEL, section 7A(6).

[2402] NER, clauses 6.5.6(c)(1), 6.5.6(c)(2), 6.5.7(c)(1) and 6.5.7(c)(2).

[2403] NER, clause 6.5.6(e)(4) and clause 6.5.7(e)(4).

The AER has jointly assessed the benchmark equity raising costs of all three DNSPs on this basis. In particular, where consultant reports have been submitted by one of the DNSPs, to the extent that the information is pertinent to all DNSPs the information has been jointly considered within this appendix.

For convenience, within this appendix references to the benchmark firm should be interpreted as a reference to a benchmark efficient DNSP that is a pure play regulated electricity network operating in Australia without parent ownership.

Where it has been necessary to refer to a draft decision for just one of the DNSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than referring to the generic term draft decision, as defined in the shortened forms.

Past AER considerations

In April 2009, the AER released final decisions (April 2009 final decisions) covering regulatory and revenue determinations for electricity distribution and transmission networks in NSW, ACT and Tasmania which included a common appendix dealing with benchmark debt and equity raising costs. The final decisions set out the AER's analysis and considerations with regard to the efficient costs of raising capital prior to the commencement of the current processes.[2404]

For simplicity, references to the April 2009 final decisions in this appendix are made to the ACT final decision only.

M.3 Regulatory proposals

The three DNSPs based their proposals on the methodology used by the AER.[2405] This identifies a hierarchy of three methods for equity raising, with differing equity raising costs and availability for each method:

- First, firms use retained earnings as a source of equity. The amount of equity raised in this manner is capped at the amount of available internal funds, determined by benchmark cash flow calculations. Note that retained earnings are dependent upon the dividend policy of the benchmark firm, which should be consistent with the assumed value of imputation credits.[2406]

- Second, firms use dividend reinvestment plans. The amount of equity raised in this manner is capped at 30 per cent of the value of outgoing dividends. Note that this too is related to the dividend policy for the firm.

- Third, firms use seasoned equity offerings (SEOs), encompassing both rights issues and placements. Although the AER considers the benchmark firm primarily

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[2404] AER, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April 2009, appendix H; AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, appendix N; AER, *Final decision, TransGrid transmission determination 2009–10 to 2013–14*, 28 April 2009; AER, appendix E; AER, *Final decision, Transend transmission determination 2009–10 to 2013–14*, 28 April 2009, appendix E.

[2405] See: AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 194 (table 8.18), 579–587.

[2406] AER, *Final decision, ACT DNSP*, 28 April 2009, pp. 251–257.

uses rights issues, the DNSPs consider a different balance between rights issues and placements is appropriate. The benchmark firm obtains all the remaining equity required via this method.

Each method was benchmarked on a per unit cost basis (that is, costs were set as a percentage of the total equity raised via that method). The proposals were:

- The Qld DNSPs proposed a unit cost for:[2407]
  - retained earnings of 0 per cent of the equity raised via this method[2408]
  - dividend reinvestment plans of 2 per cent of the equity raised via this method[2409]
  - SEOs (considered primarily as placements) of 7.8 per cent of the equity raised via this method. This figure comprises 4.5 per cent for direct equity raising costs, and 3.3 per cent for indirect equity raising costs.[2410]
- ETSA Utilities proposed a unit cost for:[2411]
  - retained earnings of 0 per cent of the equity raised via this method
  - dividend reinvestment plans of 1 per cent of the equity raised via this method
  - SEOs (considered as placements and rights issues) of 7 per cent of the equity raised via this method. This figure comprises 4 per cent for direct equity raising costs, and 3 per cent for indirect equity raising costs.

The DNSPs included various arguments in their regulatory proposals to support these debt raising cost benchmarks. Additionally, consultant reports were submitted:

- the Qld DNSPs submitted a report by Synergies Economic Consulting (Synergies) that deals with debt and equity raising costs[2412]
- ETSA Utilities submitted a report by CEG that deals with debt and equity raising costs.[2413]

2407 The AER considers that Energex implicitly adopted this methodology, since no detail was presented in its regulatory proposal on the unit costs, although Energex explicitly endorsed the Synergies report. Aspects of the Energex methodology could be deduced from the accompanying spreadsheets, but not all calculations were transparent. Energex, *Regulatory proposal*, July 2009, section 12.7.6, p. 174. Ergon Energy, *Regulatory proposal*, 1 July 2009, section 28.2.1, pp. 306–308.

2408 Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.2.1, p. 307.

2409 Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.2.4, p. 307.

2410 Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.2.3, p. 307.

2411 ETSA Utilities, *Regulatory proposal*, 1 July 2009, p. 139.

2412 Synergies, *Debt and equity raising costs: Report for Energex and Ergon Energy*, May 2009. Submitted as attachment 12.5 to the Energex regulatory proposal and attachment 534c to the Ergon Energy regulatory proposal.

2413 CEG, *Debt and equity raising costs: A report for ETSA*, June 2009. Submitted as attachment E.17 to the ETSA Utilities regulatory proposal.

M.4 Submissions

Submissions relevant to equity raising costs were received from:

- Energy Consumers Coalition of South Australia (ECCSA) on the ETSA Utilities regulatory proposal[2414]
- Energy Users Association of Australia (EUAA) on the Energex regulatory proposal.[2415]

M.5 Issues and AER considerations

The AER's analysis of equity raising costs in this appendix covers:

- selection of equity raising method
- indirect equity raising costs
- direct equity raising costs
- benchmark cash flow analysis—implementation of the equity raising cost allowance.

M.5.1 Selection of equity raising method

Regulatory proposals

All the DNSPs based their proposals on the methodology used by the AER in its April 2009 final decisions.[2416] This identifies a sequence of equity raising methods for use by the benchmark firm, with the use of retained earnings and dividend reinvestment plans, and finally use of a SEO. The key point of disagreement with the AER methodology was the format of the SEO:

- Ergon Energy, on the basis of the Synergies report, proposed that the format of the SEO should be based on the observed use of equity raising methods in the Australian market. This meant that placements were the predominant format, with some consideration of rights issues.[2417]
- Energex did not specifically address the selection of an equity raising method, but adopted the recommendations of Synergies (as already detailed for Ergon Energy).[2418]

[2414] ECCSA, *Australian Energy Regulator, SA electricity distribution revenue reset: ETSA Utilities application, a response*, August 2009, p. 27.

[2415] EUAA, *Submission to the AER on Energex and Ergon Energy regulatory proposals for the period 2010–2015*, 28 August 2009, p. 20.

[2416] AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 194 (table 8.18), 579–587.

[2417] Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.1, pp. 305–306; and Synergies, *Debt and equity raising costs*, May 2009, pp. 14–20.

[2418] Energex, *Regulatory proposal*, July 2009, section 12.7.6, p. 174; and Synergies, *Debt and equity raising costs*, May 2009, pp. 14–20.

- ETSA Utilities, based on the report by CEG, proposed that the format of the SEO should be a placement, although it did include some rights issues as anecdotal evidence.[2419]

AER considerations

In previous decisions the AER considered the type of equity raising undertaken by the benchmark firm.[2420] The current methodology includes explicit modelling of the use of dividend reinvestment plans, with additional external equity requirements based on rights issues (although some consideration is given to placements).[2421]

Synergies observed equity financing preferences in the Australian market to inform the choice of equity raising type by the benchmark firm.[2422] Synergies stated that the preferred method in the Australian market is a share placement, and that therefore the benchmark firm's practice should be based on the issue of a placement to obtain external equity, on several grounds:

- It is inappropriate for the AER to merge rights issues and dividend reinvestment plans to form a 'rights based equity' category. This union ignores substantial differences between the two types of equity.[2423]
- Once 'rights based equity' is disaggregated, placements remain the predominant form of equity raising. This is based on Australian Stock Exchange (ASX) market data from 1999–00 to 2006–07.[2424]
- This ASX data set is preferable to the AER's previous data on this issue as it is more recent and is from a more reliable source.[2425]

Similarly, CEG also stated that ASX data supports adopting placements over rights issues for use by the benchmark firm.[2426] CEG observed that in 2006–07 and 2007–08, placements were more than double rights issues (by volume). On the basis of a study by Brown and Chan,[2427] CEG stated that the level of rights issues is artificially high, since there are government regulations imposing conditions on placements. CEG considered that in the absence of these artificial restrictions, companies would show even greater preference for placements over rights issues.[2428]

In addition to market wide analysis, the AER has previously undertaken specific analysis of equity raisings by Australian utilities.[2429] In particular, this analysis looked

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2419 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139; and CEG, *Debt and equity raising costs*, June 2009, pp. 23–29.
2420 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, pp. 235–251.
2421 AER, *Final decision, ACT DNSP*, 28 April 2009, table 9.14, p. 79.
2422 Synergies, *Debt and equity raising costs*, May 2009, section 3.1.1, p. 14–17.
2423 Synergies, *Debt and equity raising costs*, May 2009, p. 15.
2424 Synergies, *Debt and equity raising costs*, May 2009, table 2, p. 17.
2425 Synergies, *Debt and equity raising costs*, May 2009, p. 17.
2426 CEG, *Debt and equity raising costs*, June 2009, p. 25.
2427 Brown, R. and Chan, H., *Rights issues versus placements in Australia: Regulation or choice?*, Company and Securities Law Journal, 2004, vol. 22, pp. 301–312.
2428 CEG, *Debt and equity raising costs*, June 2009, paragraph 96, p. 25.
2429 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, table H.5, p. 242.

at the purpose of the equity raising, and found clear patterns in which type of equity raising was used for a given purpose. Synergies stated that this research was flawed because:[2430]

- the data does not support the idea that rights issues are equivalent to dividend reinvestment plans, since rights issues are used exclusively for mergers and acquisitions, but dividend reinvestment plans are used exclusively for internal expansion and growth
- the analysis includes data from 2007–08, which should be excluded as anomalous
- no weight can be given to this data since it has not been open to independent scrutiny and is not transparent.

Ergon Energy also stated that it did not consider this data to be reliable.[2431]

Synergies concluded that the proportion of equity capital raised via dividend reinvestment plans should be set at 30 per cent, and noted that the AER implemented this approximate policy despite its flawed reasoning.[2432]

The AER considers that the market average cannot be automatically applied to the benchmark firm. As it stated in the April 2009 final decisions:[2433]

> The AER considers that, even if there was conclusive evidence that a particular method of equity raising was adopted by the majority of the market, this would not necessarily require the benchmark firm to adopt this method. In particular, since the characteristics of the benchmark firm differ markedly from the market average, it is not necessary to automatically accept the average market method as appropriate.

In this case, there is no conceptual or empirical reason presented by Synergies on why the benchmark firm would utilise types of equity raising in proportions corresponding to the market average use of each method. In its April 2009 final decision, the AER observed market average practice in order to inform its decision on the type of equity raising, not to bind it to the average.[2434] The analysis showed that rights issues, placements and dividend reinvestment plans were three types of equity raising that were large enough to provide the amount of funding required and conceptually compatible with the situation of the benchmark firm.

The AER notes that Synergies argued that the data for 2007–08 should be excluded on the basis of a large increase (1186 per cent) in dividend reinvestment plans. The AER notes that the Australian Financial Markets Association (AFMA) has since released an updated report, which includes data from 2008–09 as well as substantial revisions to previous years' data (including 2007–08 data). This data is presented in table M.1

[2430] Synergies, *Debt and equity raising costs*, May 2009, p. 19.
[2431] Ergon Energy, *Regulatory proposal*, July 2009, p. 307.
[2432] Synergies, *Debt and equity raising costs*, May 2009, pp. 19–20.
[2433] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 241.
[2434] The AER notes that clause 6.5.6(c) of the NER refers to the 'benchmark' operating expenditure that would be incurred by an "efficient" DNSP, not the average costs.

Table M.1: New capital raising for cash, ($, million)

Survey year	Rights issues	Placements	Dividend reinvestment plans	Total
2004–05	3 242	7 896	7 343	18 481
2005–06	2 468	12 817	7 321	22 606
2006–07	13 001	19 789	8 994	41 784
2007–08	12 449	20 920	11 563	44 932
2008–09	28 506	38 235	15 010	81 750
Total	59 666	99 657	50 231	209 554
Percent of total raised 2004–09 (%)	28.5	47.6	24.0	

Source: Australian Financial Markets Association, *2009 Financial Markets Report*, p. 58.

The AER considers that the broad pattern of equity issuance has not changed; in that rights issues and dividend reinvestment plans provide more equity (by volume) than placements in recent years. The AER notes that there is no longer a large anomalous increase in dividend reinvestment plans for 2007–08 (which has been revised from $115 623 million to $11 563 million) and considers that data from this financial year can be included without risk to the validity of the sample.

The AER notes that the labelling of 'rights based equity' occurred in a specific context. In its November 2008 draft decisions, the AER explained the mechanism by which underpricing rights issues did not result in a wealth transfer from old to new shareholders.[2435] CEG responded by pointing out that placements were more common than rights issues,[2436] and argued that the AER should be bound by 'what firms actually do'.[2437] The AER considered that since the mechanism by which rights issues avoid wealth transfer is shared with dividend reinvestment plans, the comparison between placements and rights issues should more properly be between placements and both rights issues and dividend reinvestment plans, jointly labelled as rights based equity.[2438] Hence, the union was appropriate in the context of a discussion on indirect costs and wealth transfer between investors.

The AER clarifies that it does not consider rights issues and dividend reinvestment plans to be equivalent in all aspects. This is self–evident from the AER methodology

[2435] AER, *Draft decision, New South Wales distribution determination 2009–10 to 2013–14*, 21 November 2008, pp. 190–192.

[2436] CEG, *Debt and equity raising costs: A response to the AER 2008 draft decisions for electricity distribution and transmission (EnergyAustralia version)*, January 2009, paragraphs 44, 50–56, pp. 14–15, 18–20.

[2437] CEG, *Debt and equity raising costs: A response to the AER 2008 draft decisions for electricity distribution and transmission (EnergyAustralia version)*, January 2009, section 2.4.5, p. 19.

[2438] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, pp. 240–243.

applying the cash flow analysis for equity raising costs,[2439] which implements dividend reinvestment plans at a separate point of the analysis (with a separate unit cost percentage) to the implementation of rights issues (as part of the external SEO unit cost).

With this background, it is then important to consider the AER's detailed analysis of the equity raising types by purpose.

As has been stated above, the AER does not consider that rights issues and dividend reinvestment plans are identical in all aspects. Hence Synergies' concern about this matter is not warranted because rights issues and dividend reinvestment plans are appropriately considered by the AER.[2440]

The AER also considers the data from 2007–08 should be included. The existence of an error in Synergies' data set does not invalidate analysis based on an entirely separate data source. In other words, 2007–08 was not an anomalous year for equity raisings such that 2007–08 should be excluded from all analysis of equity raising methods. There was simply a one–off data error, which in any case been corrected by the data provider (with the revised figure included in this document).

Synergies stated:[2441]

> …the AER has not published the precise sources of its data, nor the assumptions that underpin it, nor is it made clear whether this data has been independently verified.

The AER concurs with Synergies that information presented as part of the regulatory process should be clear and transparent. This includes accurate references to any primary data source cited, and full description of any statistical analysis undertaken. The AER considers that this aspect is particularly important for a regulatory proposal in order for the AER to verify the appropriateness of the proposed allowance.

The AER considers that the particular table in question was well referenced in the AER's April 2009 final decisions.[2442] The AER disclosed the full list of companies considered, the date range and the source documents. This compares favourably with, for example, Synergies' analysis of the underpricing of initial public offerings (IPOs),[2443] which did not present the relevant date range, names of the firms involved, or a description of the criteria for how they were selected. Similarly, when Synergies analysed the direct costs of IPOs and SEOs,[2444] they did not provide the date range, selection criteria and the names of the firms in their capital–intensive subset. The AER notes that Ergon Energy's concern over transparency of data used by the AER is inconsistent with the presentation of its own consultant report.

2439 The AER notes that CEG makes this same point; CEG, *Debt and equity raising costs*, June 2009, paragraph 97, p. 25

2440 Further, the AER observes that Synergies appears to have misunderstood the application of dividend reinvestment plans under the AER cash flow analysis to derive benchmark equity raising costs. This point is addressed later in the appendix.

2441 Synergies, *Debt and equity raising costs*, May 2009, p. 19.

2442 AER, *Final decision, ACT DNSP*, table H.5, footnote 661, p. 242.

2443 Synergies, *Debt and equity raising costs*, May 2009, p. 23.

2444 Synergies, *Debt and equity raising costs*, May 2009, pp. 27–28.

Consistent with its April 2009 final decisions, the AER considers that the data analysing equity raising by purpose is the most relevant evidence available for determining the equity raising method for the benchmark firm. The data is set out in table M.2.

Table M.2: Equity raised by Australian utility firms 1997–2008 ($, million)

Purpose of SEO	Mergers and acquisitions	Unidentified purpose	Internal expansion	Total
Placements				
Private placement	2482	431	66	2979
Share placement plan	306	115	54	475
Total placements	2788	546	120	3454
Rights based equity				
Dividend reinvestment plan	–	–	1453	1453
Rights issue	1577	600	–	2177
Total rights based equity	1577	600	1453	3630
Employee shares	–	94	–	94
Total	4365	1240	1573	7178

Source: AER, *Final decision, ACT DNSP*, 28 April 2009, table H.5, p. 242. Sample included all equity raising activities between 1997 and 2008 for the following firms: AGL, AGL Energy, Alinta, Babcock and Brown Power, DUET, Envestra, Origin and Spark Infrastructure. Data was collected from Bloomberg, annual reports, company releases and ASX announcements. Initial public offerings were excluded.

The AER further clarifies that the starting point for the data presented in table M.2 was accessing Bloomberg statistics on the value of equity raised by each company each year. The AER then examined each company's annual report, for each year in the sample, which generally contained a clear statement on the purpose of that year's equity raising activities. Where this was not sufficient to identify the purpose of the additional equity, the AER obtained individual ASX notices (and associated press releases) to further clarify the purpose. If, at this point, it was not able to clearly categorise the purpose as either internal expansion or merger/acquisition, the figure was assigned to the unidentified purpose category.

Table M.2 shows that dividend reinvestment plans are the predominant source of new equity for Australian utilities for the purposes of internal expansion.[2445] This is consistent with the current AER cash flow methodology for equity raising, which

[2445] The AER notes that table M.2 does not show that 'rights issues are used solely for mergers and acquisitions', as stated by Synergies. Around $600 million of rights issues remain unidentified and it seems implausible to state that none of this reflects internal expansion. See Synergies, *Debt and equity raising costs*, May 2009, p. 19.

assigns a higher priority to dividend reinvestment plans than either rights issues or placements. That is, the benchmark firm uses all equity available from a dividend reinvestment plan before turning to an external SEO.

The AER notes that this is not equivalent to determining that a particular percentage of the total equity required should be raised via dividend reinvestment plans.[2446] In this regard, it appears Synergies has misunderstood the application of the current AER methodology when it states:[2447]

> In any case, we note that in its conclusions, the AER appears to rely on Handley's observations in relation the [sic] proportion of equity that is to be raised by the DRP, which is 30%.

The AER methodology caps the amount of equity available from dividend reinvestment plans at 30 per cent of the total dividends paid out by the firm. This may result in all equity being sourced via retained earnings and dividend reinvestment plans. To the extent that there is an extremely large equity raising requirement, it may be that the dividend reinvestment plan provides less than five per cent of the total amount, with the remaining required equity being sourced from SEOs (rights issues and placements).

AER conclusion on selection of equity raising method

The AER has considered the material presented by the DNSPs and their consultants on the relevance of various equity raising methods for the benchmark firm. The AER concludes that:

- the benchmark firm should not necessarily adopt the equity raising method used by the majority of the market, as the benchmark firm differs markedly from the average market firm

- the use of retained earnings in preference to all other sources of equity has been accepted by all DNSPs

- the most relevant analysis of equity raising methods—conducted by the AER on Australian utility firms raising equity for internal expansion—supports the use of dividend reinvestment plans before either rights issues or placements

- external SEO type may be either a rights issue or placement, dependent on whichever is least cost.

On this basis, the AER considers that the methodology implemented by the AER in its April 2009 final decisions remains appropriate for estimating benchmark equity raising costs.

2446 For instance, if a given DNSP requires $100 million in equity over the regulatory control period, deciding that 30 percent (or any other set percentage) must come from dividend reinvestment plans.

2447 Synergies, *Debt and equity raising costs*, May 2009, pp. 19–20.

M.5.2 Indirect equity raising costs

Regulatory proposals

The three DNSPs proposed that the allowance for equity raising costs should include indirect costs:

- Ergon Energy, based on the Synergies report, proposed an indirect cost only for SEOs—modelled specifically for a placement issue—of 3.3 per cent of the total amount of equity raised via this method.[2448]

- Energex did not specifically address the identification of indirect costs, but adopted the recommendations of Synergies (similar to Ergon Energy).[2449]

- ETSA Utilities, based on the CEG report, proposed an indirect cost only for SEOs, of 3 per cent of the total amount of equity raised via this method.[2450]

Although no other indirect costs were proposed, several other statements were made by the DNSPs and their consultants regarding the existence of further indirect costs.

Ergon Energy stated that there were strong grounds for inclusion of indirect costs associated with the use of retained earnings, principally because it interfered with payout of dividends.[2451] However, Ergon Energy noted that it was difficult to establish a reasonable estimate of such costs, and so did not propose an indirect cost associated with the use of retained earnings.

Synergies stated that there were indirect costs for a rights issue:[2452]

> However, there is still an indirect cost imposed upon shareholders and that is the requirement to change the existing investment mix. Shareholders have a mix of cash and shares. A rights issue forces a shareholder to substitute cash for shares and to increase equity as a proportion of their overall investment.

However, Synergies stated that there was no robust way to estimate these indirect costs, and neither of the Qld DNSPs proposed an indirect cost associated with rights issues, instead modelling their SEO costs—direct and indirect—purely on placements.

CEG considered the allowance provided for dividend reinvestment plans and stated:[2453]

> However, it [the 1 per cent allowance for dividend reinvestment plans] does not appear to include indirect costs associated with the DRP being issued at a discount. In my view the AER should also estimate the indirect cost of any

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2448 Ergon Energy, *Regulatory proposal*, July 2009, p. 307; Synergies, *Debt and equity raising costs*, May 2009, pp. 25–26.

2449 Energex, *Regulatory proposal*, July 2009, section 12.7.6, p. 174; Synergies, *Debt and equity raising costs*, May 2009, pp. 20–26.

2450 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139; CEG, *Debt and equity raising costs*, June 2009, section 3.2.2, pp. 27–28.

2451 Ergon Energy, *Regulatory proposal*, July 2009, section 28.2.2.1, p. 307.

2452 Synergies, *Debt and equity raising costs*, May 2009, p. 24.

2453 CEG, *Debt and equity raising costs*, June 2009, paragraph 115, p. 29.

> dilution in the shares of the majority of shareholders who do not participate in DRPs.

However, no evidence is presented by CEG on this matter, and ETSA Utilities makes no reference to any indirect costs of a dividend reinvestment plan.

AER considerations

Relationship between indirect and direct costs

A key argument of both CEG and Synergies is the equivalence of indirect and direct costs. CEG stated:[2454]

> CEG has previously submitted to the AER on the need for direct and indirect costs to both be estimated and for these costs to be jointly estimated in a consistent manner. As a matter of economics, these costs are equivalent and these can be easily demonstrated.

CEG goes on to give examples of how both indirect and direct costs are incurred by a firm seeking to raise new equity. The relationship between indirect and direct costs is further described by Synergies:[2455]

> In this regard, underpricing and underwriting are inextricably linked. The greater underpricing, the lower the direct costs associated with an equity issue. The greater the direct costs associated with the issue, the lower the indirect costs.

CEG made a similar statement:[2456]

> The higher the indirect costs (lower the price) the lower will be the direct costs of marketing the capital. By contrast, the lower the indirect cost (higher the price) the higher will be the direct costs.

In economic terms, CEG and Synergies claimed that indirect costs and direct costs are substitutes, that is an increase in one leads to a decrease in the other. Alternatively, it may be conceived that a given total cost of raising capital can be split in any proportion of indirect and direct costs. Given that the AER has already indicated that direct equity raising costs are a legitimate cost for the benchmark firm, this leads to the conclusion that AER should also allow indirect costs since any indirect cost could be replaced by a direct cost of exactly the same amount.

The AER considers that for such a logic chain to hold, there must be an observed and interdependent relationship—where each may exactly substitute for the other—between indirect and direct costs. The AER notes that no empirical evidence has been submitted to demonstrate the inextricable link between indirect and direct equity raising costs.

2454 CEG, *Debt and equity raising costs*, June 2009, paragraph 44, p. 13.

2455 Both the following statements on the substitutability of indirect and direct costs were made with regard to equity raising costs. The AER discussed similar statements made in the context of debt raising costs in AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, pp. 214–221. Synergies, *Debt and equity raising costs*, May 2009, p. 20.

2456 CEG, *Debt and equity raising costs*, June 2009, p. 14.

Synergies does not provide any evidence on this matter. CEG included two statements that could be construed to provide such a link.

First, CEG implied that such evidence existed when it stated:[2457]

> Moreover, there has been a documented trend towards greater reliance on indirect costs[19] and less reliance on direct costs[20] to sell new equity issues.
>
> 19 Altinkili [sic], O. and Hansen, R., (2003) "Discounting and underpricing in seasoned equity offerings [sic]", Journal of Financial Economics, vol. 69, issue 2, pp.285–323.
>
> 20 Saunders, A., Palia, D. and Kim, D., (2003) "The Long-Run Behavior of Debt and Equity Underwriting Spreads", NYU, Stern School of Business, Finance Working Paper No. FIN–03–004.

The AER considers that the two papers cited by CEG, considered separately, do not support the statement that indirect and direct costs are interdependent substitutes. The Altinkilic and Hansen paper does not report or investigate direct equity raising costs, and so makes no statement about the relationship between indirect and direct costs.[2458] The Kim, Palia and Saunders working paper does look at the relationship between indirect and direct costs in SEOs, but reports that the two are positively related.[2459] In other words, higher direct costs are associated with higher indirect costs, and lower direct costs are associated with lower indirect costs—the opposite relationship to that asserted by Synergies and CEG.[2460]

The AER also observes that when the Kim, Palia and Saunders working paper was accepted for publication, all data and analysis related to indirect costs (underpricing) were removed.[2461] The AER therefore considers that limited weight should be given to any of the results on this issue from the working paper. Nevertheless, if anything, the working paper can only be interpreted as arguing against the idea that direct and indirect costs are substitutes.

Further, the AER considers that the two papers cited by CEG, when considered jointly, do not support the statement that indirect and direct costs are interdependent substitutes. The Altinkilic and Hansen paper documents that underpricing in the 1990s is larger than underpricing in the 1980s.[2462] The Kim, Palia and Saunders working paper presents evidence that the direct costs in the 1990s are lower than either the 1970s or 1980s (though the 1970s and 1980s cannot be distinguished from each other

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2457 CEG, *Debt and equity raising costs*, June 2009, paragraph 50, p. 14

2458 Altınkılıç, O. and Hansen, R., *Discounting and underpricing in seasoned equity offers*, Journal of Financial Economics, 2003, vol. 69, pp. 285–323. Discussion of 1980s underpricing occurs on pp. 304–305.

2459 Kim, D., Palia, D. and Saunders, A., *The long-run behaviour of debt and equity underwriting spreads*, Working paper, 2003, pp. 22–24.

2460 The Kim, Palia and Saunders working paper also investigates this tradeoff in initial public offerings (IPOs) but finds no statistically meaningful relationship; see Kim, Palia and Saunders, *Debt and equity underwriting spreads*, 2003, pp. 23.

2461 Kim, D., Palia, D., and Saunders, A., *The impact of commercial banks on underwriting spreads: Evidence from three decades*, Journal of Financial and Quantitative Analysis, December 2008, vol. 43(4), pp. 975–1000.

2462 Altınkılıç and Hansen, *Discounting and underpricing*, 2003, table 3 (pp. 298–299), pp. 304–306.

statistically).[2463] However, it would be methodologically inappropriate to attempt to unite the results from two independent studies and assert that the increased indirect costs (in the Altinkilic paper) are replacing the decreased direct costs (in the Kim, Palia and Saunders working paper).

CEG also stated:[2464]

> In addition to these studies there is a recent 2007 paper by Bortolotti, Megginson and Smart which examines underwriting and underpricing costs in both the US and Europe. The authors note the trend for increasing underpricing costs and the interrelationship of this with underwriting costs (noting that prior to the 1990's underpricing was much less common in SEOs).

The AER considers that CEG appears to have misrepresented the findings of Bortolotti et al. on the 'interrelationship' of underpricing and underwriting costs. Bortolotti et al. did not present data on underwriting or underpricing costs over time. The authors were concerned with the growth in the total value of accelerated transactions over time, but all analysis of underwriting and underpricing occurs at an aggregate level over their entire sample period (1991–2004).[2465] Bortolotti et al. stated in passing that underwriting spreads have fallen over time; but they did so by reference to the Kim, Palia and Saunders working paper (without presenting any original analysis).[2466] Bortolotti et al. noted that other researchers (including Altinkilic and Hansen) found increasing underpricing over time—but did not investigate this themselves.[2467]

Bortolotti et al. did not conduct a statistical analysis that examines the relationship between underwriting and underpricing across their full sample.[2468] The authors looked at the costs of accelerated transactions in comparison to more traditional SEO types, which provided some oblique evidence on the relationship between direct and indirect costs. For their European and rest–of–world subsets, indirect and direct costs were cheaper for accelerated transactions than for traditional SEOs.[2469] That is, accelerated transactions have both lower direct costs and lower indirect costs—again, the opposite relationship to that asserted by CEG and Synergies. The USA sample showed accelerated transactions that have higher direct costs and lower indirect costs,

2463 Kim, Palia and Saunders, *Debt and equity underwriting spreads*, 2003, pp. 10–11, and table 3 (p. 37).

2464 CEG, *Debt and equity raising costs*, June 2009, paragraph 108, p. 14; the source paper is Bortolotti, B., Megginson, W., and Smart, B., *The rise of accelerated seasoned equity underwritings*, Journal of Applied Corporate Finance, Summer 2008, vol. 20(3), pp. 35–57.

2465 Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008, pp. 37–43, particularly figure 1 (p. 38) and table 2 (p. 43).

2466 Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008, footnote 35, p. 49.

2467 Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008, footnote 41, p. 49

2468 The AER notes that Bortolotti *separately* undertook regression analysis on the impact of accelerated transactions on underpricing and underwriting. See Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008, table 7, p. 50.

2469 Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008, table 5 (p. 46) and table 6 (p. 47).

but this effect is so small that when all data is aggregated, the global conclusion is that indirect and direct costs vary in the same direction.[2470]

In summary, the AER considers the empirical evidence presented by CEG:

- does not present a robust investigation of the relationship between underwriting and underpricing
- presents several pieces of tangential evidence that, on balance, suggest indirect and direct costs are not substitutes.

The AER considers that while indirect costs (underpricing) are observed during the issuance of equity capital, there is no evidence that this is substituting for direct costs as posited by CEG and Synergies.

The AER considers that indirect equity costs have not been justified by demonstrating their equivalence with direct equity raising costs.

Regulatory framework and indirect costs

The AER has not allowed indirect costs (often labelled as 'underpricing') in the previous regulatory determinations.[2471] The foremost reason underpinning the AER's rejection of indirect costs is that the compensation for such costs is inconsistent with the current regulatory framework. As stated in the November 2008 draft decisions:[2472]

> Even if underpricing for equity raising does occur, the AER considers that:
>
> - no compensation is required for such costs because it would be inconsistent with the benchmark regulatory framework applied to determine the weighted average cost of capital (WACC)

There are two aspects of the regulatory framework which are particularly relevant to the assessment of current proposals for indirect costs:

- the framework requires consideration of outcomes for the benchmark firm, not individual shareholders
- the framework requires consistent definitions for all components.

The AER considers that a misapplication of one (or both) of these two points underlies each of the arguments made by CEG for compensation of indirect costs. It is important therefore to revisit the regulatory framework and understand what it does (and does not) state on these issues.

Firm outcomes not individual shareholder outcomes

The AER stated in its April 2009 final decisions:[2473]

[2470] Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008, table 3 (p. 44), and table 4 (p. 45).

[2471] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H.

[2472] AER, *Draft decision, NSW DNSPs*, 21 November 2009, p. 190.

[2473] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 234.

> The regulatory framework does not encapsulate personal transaction costs, including the final income tax paid by personal investors, or the rate of return given to any individual capital provider (as opposed to investors in aggregate).

The AER's consultant, Associate Professor Handley of the University of Melbourne, expressed the essence of this argument as follows:[2474]

> …the key difficulty with the NSP's claim for compensation for underpricing costs is that it would be inconsistent with the current regulatory framework. This conclusion applies irrespective of the magnitude of the underpricing and irrespective of the extent to which existing shareholders participate in the issue. The fundamental problem with the NSP's argument is a failure to recognise an important implication of the fact that underpricing costs associated with raising equity capital are incurred at the shareholder level rather than the firm level i.e. although underpricing is a cost to shareholders it is not a cost to the firm.

That is, the NEL and NER are concerned with the determination of the appropriate revenue for the firm as a whole. Components of total revenue relevant to the discussion of indirect costs include opex and return on capital, and the NER includes specific reference on how these are set for the firm.

Since the benchmark firm is owned by its shareholders, any return to equity capital can be viewed as the return provided to shareholders in aggregate. There are therefore times where it is appropriate to discuss the return to shareholders. However, there is no requirement to have regard for any particular individual shareholder, or a particular subset of shareholders.

Consistent definitions

The requirement for consistency was described by Associate Professor Handley as follows:[2475]

> The regulatory framework requires the determination of allowed revenues to the regulated firm to be undertaken on … an after company tax, before personal tax, after underpricing costs but before other personal (transactions) costs basis. The consistency principle therefore requires that regulatory cash flows be defined on a similar basis. In other words, cash flows should be after company tax, before personal tax, after underpricing costs but before other personal (transactions) costs.

That is, there is a need for first–order consistency between the various components of the model used to determine the appropriate revenue for the DNSP:

- the specification of formulae
- the delineation of cash flows
- the estimation of parameter values.

[2474] Handley, *Raising debt and equity*, 12 April 2009, p. 10.

[2475] Handley, J., *A note on the costs of raising debt and equity capital: Report prepared for the Australian Energy Regulator*, 12 April 2009, p. 10.

Finally, Associate Professor Handley also noted:[2476]

> It is important to note that not making an explicit adjustment to the cash flows for underpricing or other personal transactions costs does not mean that these costs are either ignored or assumed not to exist. Rather, underpricing and other costs are already implicitly taken into account by investors in determining the required rate of return.

Disregarding the consistency principle leads to double counting and systematic over estimation of the efficient costs. Consider the market risk premium (MRP), a parameter that is estimated as a proxy using observed (market) share prices in the presence of underpricing. That is, every time a firm sells new equity at a discount, the (market) share price reduces to reflect the dilution effect on existing shares. This reduces the capital gain (or increases the capital loss) received by the shareholders, and therefore reduces aggregate return. As such, the return to equity based on this MRP implicitly includes the (indirect) cost, and reflects the required return to equity in the presence of underpricing. It would be inconsistent with this parameter estimation to provide a separate allowance (in the cash flows) for underpricing.

The interpretation of clause 6.5.3 of the NER

CEG discussed the interpretation of clause 6.5.3 of the NER. The AER considers that this illustrates the misapplication of the two principles above—benchmark firm outcomes not individual shareholder outcomes, and consistent definitions of all components—by CEG, and therefore will address this matter.

As background, the AER made the following statement in its April 2009 final decisions, with footnote as shown:[2477]

> The AER considers that separate compensation for investor level transaction costs, including investor level taxes is inconsistent with the regulatory framework. The regulatory framework specifies that investor returns are post company tax and pre–investor tax.[631]
>
> [631] The AER notes that this is why imputation credits are deducted from the regulatory building blocks when determining total allowed revenue for the business; to the extent that they will be redeemed, they are not company taxes but pre–payment of personal taxes.

The AER notes that this statement on imputation credits encompasses both a firm–centred view of taxation, and consistency between the various components of the calculation of taxation. CEG cited this paragraph (with footnote) and stated:[2478]

> In my view, this position is internally inconsistent and attempts to make a false economic distinction between costs being borne by 'the company' and costs borne by 'the shareholders' in order to argue that only the former should be compensated.

That is, CEG explicitly disagreed with the idea that the regulatory framework is concerned with the firm, not individual shareholders. CEG further explained:[2479]

[2476] Handley, *Raising debt and equity capital*, 12 April 2009, p. 11.

[2477] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 236. Note that CEG quotes from the NSW DNSP version.

[2478] CEG, *Debt and equity raising costs*, June 2009, paragraph 64, p. 18.

> This provision in the NER [6.5.3] explicitly and specifically requires the AER to consider the returns to individual shareholders – which is precisely the opposite of what the AER claims the regulatory framework requires.

The AER considers that CEG has not correctly interpreted clause 6.5.3 of the NER. The AER notes that this clause refers to the DNSP (as a whole), and is entirely focused on the cost of taxation to the entity. The task facing the AER is to determine the return for the regulated business. It is correct that this involves consideration of the return to shareholders (in aggregate) as part of the gamma (imputation credits) parameter, but this does not change the nature of the AER's task. As stated above, there are times where it is appropriate to discuss the return to shareholders (in aggregate). However, there is no requirement to have regard for any particular individual shareholder, or a particular subset of shareholders.

CEG stated:[2480]

> While AER is arguing that the NER compensates only for costs borne by the firm and not costs borne by shareholders (such as indirect equity raising costs), what the NER actually requires is that the compensation that firms receive for corporations tax, a cost borne in its entirety by the firm, be offset by the benefit accrued to shareholders through the value of imputation credits. That is, the NER require that a benefit which is accrued by shareholders from the firm be deducted from the firm's allowed revenue. It is unclear why the AER believes that a cost incurred by shareholders on behalf of the firm should not similarly be added to the firm's allowed revenue.

The AER considers that these statements reflect the incorrect selection of the individual shareholder (instead of the benchmark firm) as the point of concern for the regulatory framework. Although imputation credits are 'a benefit which is accrued by shareholders', they can equally be viewed as a benefit generated by the firm. Assessment of shareholder characteristics (in aggregate) occurs during the estimation of gamma (the assumed utilisation of imputation credits), but it occurs only to the extent necessary to value the benefit generated by the firm. Adopting the CEG terminology, the AER considers that a cost borne by the firm (taxation payments made to the ATO) is offset against a benefit generated in its entirety by the firm (the assumed utilisation of imputation credits). This is consistent with a regulatory framework that focuses on the benchmark firm, not individual shareholders.[2481]

2479 CEG, *Debt and equity raising costs*, June 2009, paragraph 67, p. 18.

2480 CEG, *Debt and equity raising costs*, June 2009, paragraph 70, p. 19.

2481 The consideration of the value of imputation credits does not mean that the regulatory framework has shifted its concern to the rate of return required by individual shareholders. Consider the case of two shareholders: When a low income shareholder (low marginal tax rate) receives a franked dividend from the benchmark firm, this shareholder will receive the entire amount rebated back by the ATO. When a high income shareholder (high marginal tax rate) receives a franked dividend from the benchmark firm, this shareholder will still be required to pay additional tax on the dividend (since its marginal personal income tax rate is higher than the corporate tax rate). Clearly, the two individual shareholders are receiving a different (post-personal-tax) rate of return on their shareholding. Deducting the value of the franking credit from the company taxation allowance does not involve consideration of the rate of return to either shareholder.

Transaction costs

The AER observes that there are transaction costs when engaging in any equity raisings—for example, brokerage, search costs, bank fees.[2482] CEG stated:[2483]

> A new shareholder requires compensation for the cost of engaging in the equity raising (e.g. liquidating other assets) and the costs of gathering and analysing information on the equity raising.

The AER notes that liquidating other assets involves several types of transaction costs—for example, time spent managing the liquidation, broker fees, tax on any crystallised capital gain. Search costs (that is, the costs of gathering and analysing information) are a textbook example of transaction costs.

The AER has previously recognised that transaction costs occur and that they are not part of the direct cost of equity raising.[2484] However, the AER does not consider that the existence of these costs requires compensation to be provided. As stated previously:[2485]

> … the AER considers it inappropriate to determine that such transactions are 'extra' or 'forced' transactions—that would accordingly require compensation–without considering the pattern of transaction costs that an investor in the market ordinarily incurs.

Every investor in the market incurs transaction costs when managing their equity portfolio. Although the magnitude of these aggregate transaction costs is not known, the aggregate compensation received across the market is readily identified. It is the return on the market portfolio—the risk free rate plus the MRP. In this context, the AER considers that CEG is correct to state:[2486]

> If the shareholders do not expect to be compensated for the total costs that they bear then they will not supply equity capital in the first place.

The MRP (and the risk–free rate) are observed based on investor behaviour in the market where transaction costs exist (this holds true for both projections of the MRP from historical data and forward looking MRP projections based on the dividend growth model. No explicit adjustment is made to the MRP to reflect the transaction costs incurred, but they are nonetheless present when the MRP is estimated.[2487] Investors, with an expectation of incurring transaction costs, supply equity capital at this rate of return. It is theoretically and empirically sound to conclude that such an estimate of the MRP therefore provides appropriate compensation for the average

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[2482] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 237.

[2483] The AER notes that this text comes from the section labelled 'wealth transfers' (section 3.1.2.1) by CEG, but it conceptually belongs with the discussion of transaction costs as detailed in the text. CEG, *Debt and equity raising costs*, June 2009, paragraph 58, p. 16.

[2484] AER, *Draft decision, NSW DNSPs*, 21 November 2009, p. 190; AER, Final decision, ACT DNSP, 28 April 2009, appendix H, pp. 236–238.

[2485] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 2.37.

[2486] CEG, *Debt and equity raising costs*, June 2009, paragraph 64, p. 18.

[2487] The AER clarifies that this is the intended meaning of 'The market risk premium is estimated on a market portfolio that is exclusive of the transaction costs involved in maintaining that portfolio.' AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 236.

level of transaction costs in the market. The treatment of transaction costs is consistent with the estimation of the rate of return.

The key question then becomes whether or not investors in the benchmark firm have transaction costs that differ from the market average, and whether the equity raising strategy of the benchmark firm will alter the transaction costs for the investor. This point was made in the April 2009 final decisions:[2488]

> The AER considers that to demonstrate the need for an allowance on this issue, empirical evidence is required that shows that the transaction costs incurred by providing equity to the benchmark firm exceed those incurred by the market on average. Such evidence would demonstrate that regulated firms incur higher equity raising costs than the market on average, for which the market risk premium is estimated. No such evidence has been provided.

The AER set out strong conceptual grounds for considering that an investor in the benchmark firm will in fact have lower transaction costs than the market average investor (even after allowing for the equity raising strategy of the firm).[2489] Further, no empirical evidence has been presented that supports higher transaction costs for these investors relative to the market average.

In contrast to the AER's considerations on this matter, CEG chose to label the AER position as 'costs borne by shareholders must be ignored'.[2490] CEG further characterised the AER argument as:[2491]

> In summary, the AER appears to be arguing that the NER compensates investors only for the costs that are incurred by the firm and not for the costs that they personally incur on behalf of the firm.

Adopting the CEG terminology, the AER does not consider that these costs are incurred on behalf of the firm. Rather, they are incurred by each individual investor on their own behalf. Further, the AER considers that each investor is compensated for the costs they incur on their own behalf, through the market risk premium applied in the capital asset pricing model (CAPM), which implicitly includes compensation for the market average transaction costs. The AER considers this is already a conservative estimate, since the investor in the benchmark firm is likely to have below average transaction costs relative to the market.

Wealth transfer

Wealth transfer was described by Associate Professor Handley as:[2492]

> If a firm raises capital by issuing shares at a discount to the current market price then there is a transfer of wealth from the owners of the existing shares to the owners of the new shares i.e. underpricing represents the transfer of wealth (claim on the existing assets of the firm) from the owners of the existing shares to the owners of the new shares.

[2488] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 237.
[2489] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, pp. 236–238.
[2490] CEG, *Debt and equity raising costs*, June 2009, section 3.1.2.2, p. 17.
[2491] CEG, *Debt and equity raising costs*, June 2009, section 3.1.2.2, paragraph 63, p. 18.
[2492] Handley, *Raising debt and equity*, 12 April 2009, p. 6.

Both CEG and Synergies agreed that if the old and new shareholders were identical, no wealth transfer occurs.[2493] However, they stated that for sales to new investors, the wealth transfer represents a real cost.[2494]

The AER considers that this perspective is incorrect because it does not consider shareholders in aggregate. The transfer is within the group of shareholders, so there can be no net loss or gain in aggregate. For each shareholder worse off as a result of a wealth transfer, there is a shareholder better off by the exact same amount. The AER notes that the DNSPs (and their consultants) do not justify the selective identification of those shareholders who are worse off while ignoring those who are better off.

This is best understood with regard to the specific arguments made by CEG:[2495]

> In my view the AER's stance simply cannot be true. The regulatory framework must be designed to compensate shareholders for all efficiently incurred costs – whether the cost involves the company writing a cheque to a third party for $10m or selling shares to a third party at a $10m discount to the market price. Both reduce the value of the shares held by the shareholder by $10m.

The AER notes that CEG referred to 'shareholders' (plural) in the second sentence of the above paragraph, and that this may be read as referring to shareholders in aggregate. The AER considers that, if read this way, the statement is correct: the regulatory framework is designed to compensate shareholders (in aggregate) for efficiently incurred costs (in aggregate). However, the 'shareholders' could also be construed to mean a number of shareholders each considered individually. This appears to be CEG's interpretation, since it is the only reading that makes sense of the change to the singular 'shareholder' in the final sentence:[2496]

> Both reduce the value of the shares held by the shareholder by $10m.

This statement may be true in the context of an individual (existing) shareholder. It is demonstrably false in the context of shareholders *in aggregate*. Prior to the issuance of the new shares, let the value of the existing shares be X and the amount of capital that will be injected Y. After the discounted issuance of new equity, the value of the new and existing shares (in aggregate) will be $(X+Y)$. That is, the total value is unchanged, even though the distribution of that wealth may vary. By contrast, writing a cheque to a third party reduces the total wealth of shareholders (in aggregate), thus demonstrating the difference between direct and indirect costs.

The AER considers that CEG has not properly taken account of the relevant perspective of the shareholders in aggregate. In every transaction between two investors, there is a winner and a loser. Both are shareholders; in aggregate, they will receive the required return.

[2493] CEG, *Debt and equity raising costs*, June 2009, paragraph 55, p. 16; and Synergies, *Debt and equity raising costs*, May 2009, p. 20.

[2494] CEG, *Debt and equity raising costs*, June 2009, paragraph 55, p. 16; and Synergies, Debt and equity raising costs, May 2009, p. 24.

[2495] CEG, *Debt and equity raising costs*, June 2009, paragraph 65, p. 18.

[2496] CEG, *Debt and equity raising costs*, June 2009, paragraph 65, p. 18.

The AER notes that even if this wealth transfer required compensation—for clarity, the AER considers it does not—the introduction of an indirect cost allowance by a regulator does not address the inequality. This was explained by the AER in its April 2009 final decisions.[2497] However, CEG specifically considered that the AER was wrong to state:[2498]

> …the outside investors who took up new shares would also be overcompensated, since they experience no dilution effect (they had no shares to begin with) but still share in the underpricing allowance (paid to the firm as a whole).

CEG stated that this constituted an error of financial logic, and noted:[2499]

> The price new shareholders are willing to pay for the new equity will include the expected value of all future cash–flows from that equity. If the AER commits to pay for underpricing costs associated with an equity raising then, as the AER correctly points out, new shareholders will receive higher cash–flows per share purchased. However, what the AER logic fails to appreciate is that they will pay more for their shares as a consequence of such a decision. The net beneficiaries of the decision will be the existing shareholders who are selling them the issue – ie the beneficiaries will be precisely the shareholders who bear the costs.

The AER considers that this statement relies on an unreasonable assumption, involves an error of (mathematical) logic and is internally inconsistent.

The statement by CEG presupposes that the decision by the AER to allow for underpricing is not known in advance by the existing shareholders; since if they were aware of the allowance beforehand their price per share evaluation would itself adjust, with no change to the absolute underpricing level. Given that the AER issues publicly available regulatory determinations for a five year period, this is clearly an untenable assumption.

The AER also considers the logical endpoint of the underpricing allowance is not that the net beneficiaries are the existing shareholders. This is best understood with a brief mathematical exposition.

Define the following variables:

u total underpricing (and therefore total value of the underpricing allowance)

m number of existing shares

n number of newly issued shares

Wealth transfer as a result of the new share issue:

[2497] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, pp. 238–239.

[2498] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 239; cited by CEG, *Debt and equity raising costs*, June 2009, paragraph 60, p. 17.

[2499] CEG, *Debt and equity raising costs*, June 2009, paragraph 61, p. 17.

Existing shares change by $-\dfrac{u}{m}$

New shares change by $\dfrac{u}{n}$

Total change is $m\left(-\dfrac{u}{m}\right)+n\left(\dfrac{u}{n}\right)=(-u+u)=0$ (no net change)

The underpricing allowance, paid to the firm, is of value to all shares:

All shares change by $\dfrac{u}{m+n}$

The combined effect of the wealth transfer and underpricing allowance:

Existing shares change by $\left(\dfrac{u}{m+n}-\dfrac{u}{m}\right)$

New shares changes by $\left(\dfrac{u}{m+n}+\dfrac{u}{n}\right)$

Therefore the total effect on shares in aggregate is:

$m\left(\dfrac{u}{m+n}-\dfrac{u}{m}\right)+n\left(\dfrac{u}{m+n}+\dfrac{u}{n}\right)=u$ (underpricing allowance is aggregate gain)

From the perspective of existing shares:

$\dfrac{u}{m+n}<\dfrac{u}{m}\Rightarrow\left(\dfrac{u}{m+n}-\dfrac{u}{m}\right)<0\Rightarrow -ve$ (existing shares lose value)

From the perspective of new shares, two outcomes are possible.

If the value of the underpricing allowance per share was not included in the price paid:

$\left(\dfrac{u}{m+n}+\dfrac{u}{n}\right)\Rightarrow +ve$ (new shares gain value)

If the value of the underpricing allowance per share was included in the price paid:

$\left(\dfrac{u}{m+n}+\dfrac{u}{n}\right)-\dfrac{u}{m+n}\Rightarrow\dfrac{u}{n}\Rightarrow +ve$ (new shares gain value)

Even if the new shareholders are willing to raise their per–share evaluation by the full value of the underpricing allowance to them, the difference will never be recovered. New shareholders remain net beneficiaries, existing shareholders who do not take up new shares remain net losers; and existing shareholders who do take up new shares are indeterminate.[2500] The allowance proposed by CEG cannot eliminate the problem that it is designed to address.

The AER also notes it is internally inconsistent for CEG to attempt to apply a net present value (NPV) calculation to the underpricing allowance, without considering the NPV of the other components of the transaction. Prior to this point, underpricing has been defined by CEG with regard to the market price of the share. A consistent application of NPV assessment would show that the underpricing does not require compensation.

Consider a company that has a current (market) share price of $10. The potential new investor undertakes an analysis of the NPV of the future cash flows of the business and arrives at a value of $9 per share, which is the asking price for new equity. The new investors' assessment may be either correct or incorrect.

If the assessment of a $9 per share NPV for all future cash flows is accurate, then the current market share price is overvalued. Selling new equity at $9 does not present a loss to the company, since it will gain $9 in new capital in exchange for a claim on future cash flows worth $9 per share. Although there may be a wealth transfer away from existing shareholders on paper, this does not reflect any actual variation in the NPV of future cash flows accruing to the existing shareholder.

Since the market share price after the equity raising will fall, these existing shareholders have lost the opportunity for a windfall gain by selling the share (worth $9) at $10 on the secondary market. However, the regulatory framework is not concerned with providing such an opportunity for windfall gain. Further, any sale at this price would be a windfall loss to the shareholder who buys on the share market at $10—in aggregate, there is no net gain to shareholders. In summary, the AER considers that if the NPV of the share is below the market share price, the underpricing does not represent a cost to the shareholders in aggregate, and requires no compensation. This occurs even in the absence of an indirect cost allowance.

The AER observes that there is a large body of academic evidence supporting the idea that firms issue shares when equity prices are overvalued.[2501] Accordingly, the scenario where the NPV of future cash flows is below the market price could plausibly account for the underpricing observed by CEG and Synergies.

[2500] Existing shareholders who do take up new shares will be either net beneficiaries or net donors dependent upon the relative proportions of existing and new shares. The case of these participating shareholders is addressed in more detail later in the appendix.

[2501] Myers, S. C. and Majluf, N. S., *Corporate financing and investment decisions when firms have information that investors do not have*, Journal of Financial Economics, 1984, vol. 13(2), pp. 187–221; Karpoff, J. M. and Lee, D., *Insider Trading Before New Issue Announcements*, Financial Management, Spring 1991, vol. 20(1); Spiess, K. D. and Affleck–Graves, J., *Underperformance in long–run stock returns following seasoned equity offerings*, Journal of Financial Economics, 1995, vol. 38(3), pp. 243–267; Bayless, M. and Chaplinsky, S. J., *Is There A Window of Opportunity for Seasoned Equity Issuance?*, Journal of Finance, March 1996, vol. 51(1); Jindra, J., *Seasoned Equity Offerings, Overvaluation, and Timing*, 2000; and Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue?*, *Accounting and Finance*, 2006, vol. 46, pp. 191–219.

Alternatively, consider the scenario where the $9 per share NPV is inaccurate, and the market share price of $10 accurately reflects the NPV of future cash flows. If the new investor purchases the share at $9 then a wealth transfer occurs. The new investor gains more than $9 per share in NPV, and there is an offsetting loss for existing shareholders.[2502] However, there is no change in the aggregate NPV of free cash flows, and therefore no loss to shareholders in aggregate that requires compensation.

If an indirect cost allowance is provided by the regulator, this will affect the NPV both before and after the new shares are issued.[2503] The wealth transfer cannot be eliminated, since the allowance raises both the NPV of the prospective investor and the true NPV of the company. In summary, the AER considers that if new investors' calculation of NPV is below the true NPV of the share, although a wealth transfer occurs, the underpricing does not represent a cost to the shareholders in aggregate, and requires no compensation. Further, adding an indirect cost allowance does not eliminate the wealth transfer.

The AER considers that the key question then becomes why the prospective investor arrived at a lower NPV than the true NPV of free cash flows. There are important theoretical information asymmetry considerations here, since the potential investor must obtain information about the timing and certainty of the firm's future cash flows.[2504] This is why the regulator makes allowance for direct equity raising costs, ensuring that the firm can communicate (via prospectus or other avenues) its current financial status. However, information asymmetry is vastly reduced for the regulated firm, given that the regulator sets out the cash flows for the business in advance, and that these are publicly available. The only remaining reason for arriving at a lower NPV is the adoption of a higher discount rate. The AER notes that this is at odds with the adoption of the CAPM, which requires that all investors have the same risk profile and require the same return to equity.

In a related matter, CEG stated that the AER had inappropriately used the word 'benefit':[2505]

> Whether or not new shareholders 'benefit' from this payment is irrelevant – just as it is irrelevant whether the printing firm used by the firm to print its prospectuses 'benefits' from being paid to perform this task. Both new investors and the printing firm benefit in some sense from the payments that they receive.

The AER considers that examining the statement in context makes clear how the word 'benefit' should be read:[2506]

> The AER considers that under such a scenario, two sources of overcompensation would likely result. Original shareholders who bought new shares would be overcompensated, since the dilution effect would already be

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2502 The exact balance of gain and loss per share will depend on the proportion of new shares to existing shares, and the proportion of existing shareholders who take up new shares.

2503 Absent the CEG assumption that the regulator can surprise the business and provide an allowance it had not indicated it would provide.

2504 For example, see Eckbo, B. E. and Masulis, R. W., *Adverse selection and the rights offer paradox*, Journal of Financial Economics, 1992, vol. 32, pp. 293–332.

2505 CEG, *Debt and equity raising* costs, June 2009, paragraph 58, p. 16.

2506 AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 239.

> offset by the new shares they purchased, and they would also receive the benefit of the proposed underpricing allowance. Additionally, outside investors who took up new shares would also be overcompensated…

The full paragraph reveals that the benefit is the payment received by the shareholder (or printer, to use the CEG example). There is overcompensation because payment made to the entity is of greater value than the item exchanged for the payment (the capital contribution of the shareholder, or the prospectus from the printer).

With this understanding, the printing example put by CEG can be recast to correctly illustrate the conundrum. Consider two printers, who can produce identical prospectuses (required for the equity raising) but quote differing prices: one quotes $1 million, the other $2 million. The AER considers that providing an allowance to the regulated firm to pay the latter printer $2 million would be overcompensation, since the efficient cost of printing the prospectus is $1 million. The NER requires the level of opex to reasonably reflect the efficient costs,[2507] so (in this case) the AER would not set direct equity raising costs above $1 million.

In the context of potential investors, offering a higher price for the new equity equates to requiring a lower return on capital. Clearly, if there are two investors, with the same risk profile, offering to provide equity to the benchmark firm, but one requires a lower return on capital than the other, the AER considers that the efficient return on capital is the lower of the two. This is the correct context for interpretation of 'overcompensation'—where the capital provider receives a greater return on capital (payment) than the true worth of the capital (the item exchanged for the payment).

Participating shareholders

The AER observes that both CEG and Synergies perpetuate an error—that no existing shareholders participate in placements—that was addressed in the April 2009 final decisions:[2508]

> Associate Professor Handley observed that CEG and Carlton assume that no existing shareholders participate in their benchmark firm placements and stated this was an unrealistic assumption. The AER concurs with Associate Professor Handley's view. The AER considers that it is more plausible to infer that placements are regularly taken up by a mix of old and new shareholders.

The AER considers that, for any capital raising, there are three categories of shareholders:

- new shareholders, who did not previously own the shares but take up the new equity offer
- non–participating shareholders, who hold existing shares but do not take up the new equity offer

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[2507] NER, clause 6.5.6(c)(1).

[2508] AER, *Final decision, ACT DNSP*, 28 April 2009, appendix H, p. 239; source document is Handley, *Raising debt and equity*, 12 April 2009, p. 6.

- participating shareholders, who hold existing shares and in addition take up the new equity offer.

Participating shareholders both pay out the wealth transfer (as existing shareholders) and receive the wealth transfer (as new shareholders), so there is no indirect cost, even at an individual shareholder level.[2509] This is of course, the reason why the underpricing discount is irrelevant for a non–renounceable rights offer, since all shareholders are participating shareholders.[2510]

CEG and Synergies failed to account for the existence of participating shareholders in an equity raising.[2511] Any market observed measure of underpricing needs to be adjusted for the proportion of that placement taken up by participating shareholders. CEG and Synergies, without presenting any empirical evidence on the matter, assume that there are zero participating shareholders, in spite of the strong conceptual argument that this will not be the case. Each of the presented estimates of indirect costs therefore systematically overestimates the true extent of the wealth transfer.

CEG's arguments also fail on a longitudinal analysis of shareholder returns. Consider an investor who currently holds no shares of the benchmark firm but intends to do so by taking part in the next capital raising by the firm. According to the CEG perspective, at the next capital raising the investor must be paid (via underpricing) by the existing shareholders to take up the share and become a new shareholder. At subsequent capital raisings, this shareholder is now an existing shareholder, and must pay (via underpricing) other prospective investors to become new shareholders. This continues until the existing shareholder decides they no longer want to hold shares of the benchmark firm and sells out.

At each capital raising, the exact loss or gain to a particular shareholder depends on the extent of underpricing, the relative proportion of shares offered to new shareholders, and whether they themselves take part in providing new capital. The aggregate amount paid (via underpricing) to new shareholders must be paid (via underpricing) by existing shareholders. Further, every existing shareholder was initially a new shareholder—so this is a zero sum game. Identification of a subset of shareholders who are net losers from the underpricing transfers necessarily involves the identification of a complementary subset of shareholders who are net winners. Any claim for an increased return on capital to compensate the net losers should be consequent on a claim to reduce the return on capital to those who are net winners from underpricing.

CEG stated that the AER's position:[2512]

2509 The AER notes that the exact impact of underpricing depends on the proportion of new shares taken up by the participating shareholder relative to the proportion of new shares issued by the firm as a whole. Nonetheless, this does not affect the core of this argument.

2510 This point is specifically acknowledged by CEG. CEG, *Debt and equity raising costs*, June 2009, paragraph 55, p. 16.

2511 CEG, *Debt and equity raising costs*, June 2009, paragraphs 79–80, p. 21

2512 CEG, *Debt and equity raising costs*, June 2009, p. 23–28; Synergies, *Debt and equity raising costs*, May 2009, pp. 21–26.

> …is untenable can be shown by reflecting upon a hypothetical efficient regulated business which is considering raising equity in two ways:
>
> - method 1 involves directs [sic] costs (cheques written by the company) of $5m and indirect costs borne by shareholders of $5m; or
>
> - method 2 involves direct costs of $1m and indirect costs borne by shareholders of $12m.
>
> Clearly, method 1 is most efficient with the lowest total cost ($10m). Method 2, with $13m in total costs is higher cost. However, method 2 has the lowest direct costs. How would the AER and Professor Handley suggest that the NER requires the firm to be compensated?

The question appears difficult to answer only because of the incorrect phrasing of the problem. Following the reasoning above, the indirect component must consist of personal transaction costs (for this example, set at $1 million) and wealth transfer between groups of shareholders. A correct description of the problem then becomes:

- Method one involves:
  - $5 million in direct costs
  - $1 million in indirect costs, reflecting personal transaction costs of shareholders
  - $4 million in indirect costs that reflects transfers from one group of shareholders to another group of shareholders.
- Method two involves:
  - $1 million in direct costs
  - $1 million in indirect costs, reflecting personal transaction costs of shareholders
  - $11 million in indirect costs, reflecting transfers from one group of shareholders to another group of shareholders.

The AER therefore considers that the NER requires the efficient equity raising cost be $1 million, using method two. The shareholders will recover their personal transaction costs via the return on equity, since this is consistent with the estimation of the MRP as an input to the CAPM. The transfer represents no net cost to the business, or to shareholders in aggregate, and requires no compensation at the firm level. Further, to the extent that shareholders appear in both transfer groups—that is, they are existing shareholders who participate in the capital raising—there is no net cost on the individual shareholder level. Finally, to the extent that repeated capital raisings occur across time, the transfer groups will have identical membership—since all new shareholders become existing shareholders—and there will be no net cost on the individual shareholder level.

AER conclusion on indirect equity raising costs

The AER has considered the material presented by the DNSPs and their consultants on the inclusion of indirect equity raising costs. The AER concludes that:

- there is no evidence to support the claim that indirect costs require compensation simply because of their relationship with direct costs
- the DNSPs (and their consultants) have not correctly interpreted the regulatory framework with regard to:
  - the consideration of consistent formulae, cash flows and parameters
  - the consideration of the benchmark firm outcome, not individual shareholder outcomes
- an indirect cost allowance for personal transaction costs is not consistent with a cost of equity estimated in the presence of personal transaction costs. That is, compensation for personal transaction costs is already included in the market risk premium and therefore the cost of equity
- an indirect cost allowance for wealth transfer is not consistent with consideration of the benchmark firm outcome (as opposed to individual shareholder outcomes) since there is no loss of wealth in aggregate. Further, the indirect cost allowance would not eliminate the existence of wealth transfers in any case.

Having regard to the benchmark expenditure that would be incurred by an efficient DNSP, and other opex factors (or capex factors as the case may be), the AER considers that the proposed indirect equity raising costs do not reasonably reflect efficient costs of achieving the opex objectives (or capex objectives as the case may be) and the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the objectives.[2513] There is therefore no reasonable basis for provision of such an allowance.

M.5.3 Direct equity raising costs

Regulatory proposals

The Qld DNSPs proposed direct costs for:[2514]

- dividend reinvestment plans of 2 per cent of the equity raised via this method
- SEOs of 4.5 per cent of equity raised via this method.

ETSA Utilities proposed direct costs for:[2515]

[2513] NER, clause 6.5.6(c), 6.5.6(e), 6.5.7(c) and 6.5.7(e).

[2514] Energex did not explicitly adopt these unit costs, but simply endorsed the Synergies report which contained them. Energex, *Regulatory proposal*, July 2009, p. 174; and Ergon Energy, *Regulatory proposal*, July 2009, p. 307.

[2515] ETSA Utilities, *Regulatory proposal*, July 2009, p. 139.

- dividend reinvestment plans of 1 per cent of the equity raised via this method
- SEOs of 4 per cent of equity raised via this method.

AER considerations

Retained earnings

The AER notes that the DNSPs have adopted the AER's approach for the cash flow analysis, which does not include any direct cost associated with the use of retained earnings to fund the equity requirements of the benchmark firm.

Consistent with its April 2009 final decisions,[2516] the AER accepts this aspect of the DNSPs' proposals and considers that there is no direct cost to be applied in the use of retained earnings.

Status as a government owned entity

In its submission, the EUAA stated that the equity raising costs proposed by Energex seem unreasonable. The EUAA noted:[2517]

> Energex is owned by the Queensland Government, who arranges Energex's debt and provides Energex's equity. The AER should not allow any expenditure in this area unless there is clear demonstration that benefits will exceed costs.

The AER notes the equity raising allowance is not set based on the actual expenditure incurred by Energex or any other DNSP. Consideration is given to the circumstances of the relevant DNSP,[2518] as well as the benchmark expenditure that would be incurred by an efficient DNSP.[2519] The AER also considers competitive neutrality principles for the treatment of government owned firms.[2520] The AER considers that an efficient firm may incur benchmark direct equity raising costs.

Dividend reinvestment plans

Synergies submitted that Associate Professor Handley referred to the [direct] costs of dividend reinvestment plans being between zero and 2.5 per cent.[2521] The AER notes the lower bound of this range was based on a 2004 ACG report, which estimated that underwriting costs for dividend reinvestment plans were likely to be zero.[2522] The upper bound of this range was based on a report prepared by Tony Carlton, which claimed underwriting costs for dividend reinvestment plans were being charged at 2.5 per cent.[2523] However, Associate Professor Handley stated in his report that

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[2516] AER, *Final decision: ACT DNSP*, 28 April 2009, pp. 247–250.
[2517] EUAA, *Submission to the AER*, August 2009, p. 20.
[2518] NER, clause 6.5.6(c)(2) and 6.5.7(c)(2).
[2519] NER, clause 6.5.6(e)(4) and 6.5.7(e)(4).
[2520] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 235.
[2521] Synergies, *Debt and Equity Raising Costs*, May 2009, p. 29.
[2522] Handley, *Raising debt and equity*, 12 April 2009, pp. 26–27.
[2523] Handley, *Raising debt and equity*, 12 April 2009, pp. 27–28. Source paper is Carlton, T., *Indirect costs of equity and debt raising: Report prepared for Energy Australia*, 12 January 2009.

Carlton's claim that underwriting fees of 2.5 per cent were being charged should be investigated further.[2524]

The AER noted in its April 2009 final decisions that Carlton's claim in respect of underwriting costs being charged at 2.5 per cent only applied to the equity raised from underwriters. The AER also noted that in the one example provided by Carlton as evidence that underwriting fees were being charged at 2.5 per cent, only about half the equity raised from dividend reinvestment was from underwriters and the rest was from existing shareholders.[2525] Therefore, Carlton's estimate of the direct costs of raising equity from dividend reinvestment should only be about half of 2.5 per cent of total funds raised through dividend reinvestment plans.

Synergies submitted that based on its analysis of the costs incurred by ConnectEast, RiverCity Motorway Group, Brisconnections and David Jones in recent dividend reinvestment plans, the costs associated with dividend reinvestments are between 2 and 2.5 per cent. Synergies has not provided details of its analysis or the data it used to arrive at this estimate of the direct costs of raising equity through dividend reinvestment plans.

However, Synergies' estimate of dividend reinvestment plan costs appears to apply the cost of underwriting fees measured as a percentage of each share underwritten, to the total equity raised through dividend reinvestment plans. As discussed above, the AER considers that the percentage of shares actually taken up by underwriters should be taken into account when estimating the direct cost of raising equity through dividend reinvestment plans. Furthermore, the AER notes that if the total direct costs of dividend reinvestment plans were applied to the total equity raised through dividend reinvestment, the examples provided by Synergies would support an estimate of around 1 per cent.[2526]

In particular, the AER notes that in relation to ConnectEast, the total direct costs of two recent dividend reinvestment plans as a percentage of total equity raised were between 1.2 and 1.4 per cent of total equity raised. In relation to RiverCity Motorway Group, the corresponding figure is approximately 0.6 per cent.

Synergies also submitted that non–renounceable rights issues are very similar to dividend reinvestment plans. Based on this assumption, Synergies analysed the underwriting costs of non–renounceable rights issues by six different companies, including three energy companies.[2527] Synergies submitted that this analysis supports an estimate of 2 per cent for underwriting costs associated with dividend reinvestment plans.

2524 Handley, *Raising debt and equity*, 12 April 2009, p. 28, footnote 62.

2525 See for example AER, *Final decision, ACT DNSP*, 28 April 2009, p. 257; AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 585.

2526 Where total direct costs are measured as total underwriter fees.

2527 The AER notes that Synergies report states that this analysis was conducted on DRPs, but the AER has assumed that this is a typographical error and the analysis was actually conducted on non-renounceable rights issues, see Synergies, *Debt and equity raising costs*, May 2009, p. 30.

The AER does not consider it appropriate to use the direct costs of non–renounceable rights issues to estimate the direct costs of dividend reinvestment plans.[2528] Although non–renounceable rights issues may have similar characteristics to dividend reinvestment plans from an individual shareholder's perspective, the direct costs are not identical from the firm's perspective.

The AER considers that, from the firm's perspective, the direct costs of non–renounceable rights issues are likely to be more similar to the direct costs of renounceable rights issues than the direct costs of dividend reinvestment plans.[2529] Therefore, a distinction should not be made between non–renounceable and renounceable rights issues when estimating the direct costs of rights issues generally. Based on this assessment, the AER has considered the direct costs of rights issues (incorporating both renounceable and non–renounceable) along with the direct costs of other SEOs to estimate the equity raising costs allowance, which is discussed below.

In its April 2009 final decisions, the AER analysed the costs of raising equity using a sample of five dividend reinvestment plans by three Australian energy network businesses.[2530] Based on this analysis the AER estimated a median direct cost of raising equity of 0.75 per cent of the total equity raised through dividend reinvestment plans. The AER considered that a conservative estimate of 1 per cent was appropriate.[2531]

The AER considers that it is appropriate to limit the sample to energy network businesses or firms with similar characteristics to a regulated business (that is, stable cash flows). However, given the small sample size, in order to achieve a more statistically robust estimate the AER has also estimated the direct costs of dividend reinvestment plans using a sample of 20 ASX listed Australian firms, as shown in table M.3. Based on the larger sample the median direct cost of raising equity through dividend reinvestment plans is 0.54 per cent.

[2528] As noted by Synergies in its report 'merging data on dividend reinvestment plans and rights issues should be undertaken with extreme caution.' See Synergies, *Debt and equity raising costs*, May 2009, p. 30 and CEG, *Debt and equity raising costs*, June 2009, p. 15.

[2529] For example, the two forms of rights issue will be implemented in a similar manner, but dividend reinvestment plans are implemented in a different manner.

[2530] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 258 and AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 585.

[2531] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 258 and AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 585

Table M.3: Firms included in AER analysis of direct costs of dividend reinvestment plans (2007–08 and 2008–09)

AGL Energy Ltd	Templeton Global
Macquarie Office Trust	Essa Australia
Rivercity Motorway Group	Whitefield Ltd
Goodman Fielder.	Nomad Modular Building
Ramsay Health Care	APN European Retail Property Group
Energy Developments	Mirrabooka Investments Ltd
Cedar Woods Property	CVC Ltd
AMCIL Ltd	Tag Pacific Ltd
Ausdrill Ltd	Australian Leaders Fund
Ironbark Capital Ltd	Oaks Hotels & Resorts Ltd.

Source: AER analysis of Bloomberg, annual reports.
Note: The AER identified candidate firms using equity raising figures from Bloomberg, then consulted the company's annual reports for the last two years to identify direct equity issuance costs associated with dividend reinvestment plans.

Based on the analysis above, which suggests a median direct cost in the range of 0.54 to 0.75 per cent, the AER considers that 1 per cent remains a conservative estimate. Therefore, consistent with its previous decisions, the AER considers that 1 per cent is an appropriate estimate of the direct costs of raising equity through dividend reinvestment plans for the purposes of this draft decision.

Seasoned equity offerings—academic estimates

CEG stated that the direct cost of equity raising should be set with regard to the estimates in a paper by Lee, Lochhead, Ritter and Zhou.[2532] Lee et al. investigated the costs of raising capital in the USA between 1990 and 1994, and reported an average gross spread for utility companies of 4.01 per cent.[2533] Lee et al. also reported an average gross spread for non–utilities of 5.57 per cent, which CEG noted is broadly consistent with the estimate of Kim, Palia and Saunders of 5.01 per cent for the same category.[2534] To the base underwriting spread for utilities, Lee et al. added 0.91 per cent for other direct costs, to estimate a total direct equity raising costs of 4.92 per cent.[2535]

[2532] CEG, *Debt and equity raising costs*, June 2009, paragraph 90, p. 23; citing Lee, I., Lochhead, S., Ritter, J. and Zhao, Q., *The Costs of Raising Capital*, The Journal of Financial Research, Spring 1996, vol. 19(1), pp. 59–74.

[2533] Lee et al., *The Costs of Raising Capital*, Spring 1996, table 2, p. 64.

[2534] CEG, *Debt and equity raising costs*, June 2009, paragraph 92, p. 24. Source data is from Lee et al., *The Costs of Raising Capital*, Spring 1996, table 2, p. 64; and Kim, Palia and Saunders, *Debt and equity underwriting spreads*, 2003, pp. 9, 34 (table 1).

[2535] Lee et al., *The Costs of Raising Capital*, Spring 1996, table 2, p. 64.

CEG also noted that a more conservative estimate based on the Lee et al. study would be to exclude small equity raisings (those below US$20 million), which brings the total direct equity raising costs down to 4.06 per cent (comprising 3.60 per cent underwriting spread and 0.46 per cent for other direct costs).[2536]

The AER observes that the Lee et al. paper showed that direct equity costs, as percentage of total equity raised, decreased as the equity raising size increased.[2537] A more conservative estimate from the same paper would be to only include equity raisings larger than US$100 million, which would further lower the direct equity raising costs to 3.07 per cent (2.89 per cent for underwriting spread, and 0.18 per cent for other direct costs).[2538] The AER notes that this is would be a more appropriate equity issue size for Energex, Ergon Energy and ETSA Utilities and that the benchmark firm has some ability to aggregate its equity raising activities within the regulatory control period to minimise costs. Further, the AER observes that if CEG considered the Saunders et al. estimate (5.57 per cent) to be 'broadly consistent' with the Lee et al. estimate for the same category (5.01 per cent) then it should similarly find the Lee et al. estimate of 3.07 per cent (based on a more appropriate equity issue size) was 'broadly consistent' with the AER's estimate of 2.75 per cent.[2539]

The AER considers that the circumstances of firms studied in the Lee et al. paper do not closely match the circumstances of the benchmark firm. Aside from the concerns with country source of data (US firms instead of Australian firms) and age of the results (now more than 15 years old), the Lee et al. study excludes all rights issues, which is considered to be the principal means of raising external equity for the benchmark firm. The AER has previously set out this issue and cautioned reliance on the Lee et al. study.[2540]

CEG also stated that the costs of raising equity in the US are lower than the costs of raising equity in Australia—so even if firms in the US are not a perfect match for the benchmark firm, the Lee et al. estimates based on US data provide a lower bound estimate for the Australian costs.[2541] The AER considers that, although it may be plausible that the costs of raising equity are lower in the US, this does not imply that the costs of equity for every category of firm and every type of equity raising will be lower.[2542]

2536 CEG, *Debt and equity raising costs*, June 2009, paragraph 90, p. 23; citing Lee et al., *The Costs of Raising Capital*, Spring 1996, table 2, p. 64.

2537 Lee et al., *The Costs of Raising Capital*, Spring 1996, pp. 63–64.

2538 AER analysis of Lee et al., *The Costs of Raising Capital*, Spring 1996, table 2, p. 64.

2539 There is 11.2 per cent difference between the Saunders et al. and Lee et al. estimates for gross underwriting costs for non-utilities, and 11.6 per cent difference between the AER (April 2009) and the Lee et al. estimates for total underwriting costs for utilities raising over $100 million.

2540 AER, *Final decision, ACT DNSP*, April 2009, p. 250.

2541 CEG, *Debt and equity raising costs*, June 2009, paragraphs 93–95, pp. 24–25.

2542 The AER notes that the only paper cited by CEG that deals with international comparison of equity costs is that by Bortolotti, Megginson and Smart. This deals with global capital flows at a very high level, such that it is difficult to make any comparison with the circumstances of the benchmark firm. For example, it makes no attempt to assess the cost of capital for utilities or regulated firms, and aggregates all placements and rights issues. See Bortolotti, Megginson and Smart, *Accelerated seasoned equity underwritings*, 2008.

CEG stated that the exclusion of rights issues is not an issue because placements are the more common form of equity raising in the Australian market.[2543] The AER considers that CEG is assuming that the market average will automatically define the situation of the benchmark firm, and that this error has been addressed in section M.5.1 of this draft decision. Further, the most relevant evidence on equity raising activities by Australian utilities in the circumstances of the benchmark firm indicates that rights issues are the predominant form of equity raising.

Accordingly, the AER considers that the estimate of direct raising costs from the Lee et al. study can not be relied on to determine the benchmark direct cost of equity raising.

Seasoned equity offerings—updated analysis

Synergies submitted that, based on its analysis of 87 Australian and 75 US equity issues, it has estimated direct equity raising costs to be 4.5 per cent of total capital raised.[2544]

The AER has previously considered equity raising costs data from the US in its April 2009 final decisions.[2545] It considers that data from the US equity market is of limited relevance in estimating the direct costs of raising equity in Australia for the benchmark firm. Consistent with its previous decisions, the AER considers that data from the Australian equity market provides a more reliable basis for estimating direct equity raising costs for the purposes of this draft decision. Therefore, only data from the Australian equity market should be used to determine the benchmark equity raising costs allowance.

In addition to incorporating US equity issues, Synergies' estimate of direct equity raising costs included the costs from IPOs and SEOs.[2546] The AER notes that IPO costs represent the cost of establishing a new firm, whereas SEOs represent the costs of raising additional equity capital and therefore is more appropriate in the context of establishing benchmark equity raising costs associated with capital expenditure.

The purpose for which regulated firms need to raise additional equity capital is to fund new capital expenditure, subsequent to the establishment of the initial regulatory asset base. Therefore the AER considers that the equity raising costs allowance should be based on an estimate of the costs of raising additional equity capital (SEO costs), not the costs of establishing a new firm (IPO costs). This is consistent with previous advice from ACG, which recommended that the costs of raising equity for the purpose of funding new investment should be estimated using the transactions costs of SEOs.[2547]

The AER also notes that the direct costs of IPOs are likely to be significantly higher than the direct costs of SEOs. In 2004 ACG advised that although the fee structure of SEOs mirrors that of IPOs, the tasks involved with SEOs are likely to be much less

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2543 CEG, *Debt and equity raising costs*, June 2009, paragraphs 96–97, p. 25.
2544 Synergies, *Debt and equity raising costs*, May 2009, pp. 27–29
2545 AER, *Final decision, ACT DNSP*, 28 April 2009, p. 250.
2546 Synergies, *Debt and equity raising costs*, May 2009, p. 27
2547 ACG, *Debt and equity raising costs*, December 2004, p. xii.

complex.[2548] ACG advised that direct costs related to SEOs are likely to be much lower than direct costs related to IPOs.[2549]

For the reasons outlined above, the AER does not consider that Synergies' estimate of the direct costs of raising equity was arrived at on a reasonable basis due to the inclusion of inappropriate data (US equity issues as well as costs of IPOs).

CEG submitted that direct equity raising costs are 3 per cent of the total amount raised.[2550] This is based on a report by Lee et al. and recent equity raisings by three existing Australian utilities—Envestra, DUET and SP AusNet. As discussed above, the AER does not consider that the Lee at al. report provides a reliable basis for estimating direct equity raising costs for the purposes of this draft decision. Further, although the selection of three recent equity raisings by Australian utilities provides anecdotal evidence of equity raising costs, this does not form a robust data set from which to establish a benchmark allowance.

The AER is not satisfied that the estimates of direct equity raising costs submitted by Synergies and CEG are reasonable. The AER considers that the methodology it used in the April 2009 final decisions remains the best approach for estimating direct equity raising costs.[2551] This methodology is based on that recommended by ACG in its 2004 report prepared for the ACCC[2552] and uses the costs of SEOs issued by Australian firms to estimate direct equity raising costs.

In its April 2009 final decisions the AER estimated the direct costs of raising equity to be 2.75 per cent.[2553] The AER has updated this estimate using the latest available data on 30 SEOs issued by Australian firms between 2007 and 2009.

The AER notes that the recommended methodology in the 2004 ACG report was to use a sample of Australian companies with stable cash flows to estimate the direct equity raising costs for regulated businesses. However, the AER considers that while it is preferable to analyse only those companies with similar characteristics to a regulated firm (for example, stable cash flows), this would result in a very small sample size using the available data—such as the three firms referred to by CEG.

To achieve a more statistically robust basis for estimating direct equity raising costs the AER broadened its sample to 30 Australian firms that have issued SEOs recently. The AER considers that a sample of 30 firms provides a more statistically robust basis for estimating equity raising costs and also likely to provide a conservative estimate. Based on this updated sample, the AER estimates a median cost of 3 per cent for direct equity raising costs.

[2548] ACG, *Debt and equity raising costs*, December 2004, p. 65.
[2549] ACG, *Debt and equity raising costs*, December 2004, p. 65.
[2550] CEG, *Debt and equity raising costs*, June 2009, p. 26.
[2551] AER, *Final decision, ACT DNSP*, 28 April 2009, pp. 251, 261.
[2552] ACG, *Debt and equity raising costs*, December 2004.
[2553] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 261 and AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 588.

AER conclusion on direct equity raising costs

The AER has considered the material presented by the DNSPs and their consultants on the best estimate of direct equity raising costs. The AER concludes that:

- based on the AER's analysis of recent dividend reinvestment plans in Australia, the best estimate of direct costs of raising equity through dividend reinvestment plans is 1 per cent
- the available academic estimates of direct equity raising costs for SEOs involve a differing context to the circumstances of the benchmark firm (in country, time period, firm type) and therefore do not provide a relevant estimate
- based on the AER's analysis of recent SEOs in Australia, the best estimate of direct equity raising costs for SEOs is 3 per cent of the equity raised via this method.

On this basis, the AER considers that the use of these unit costs represent the best estimate of direct equity raising costs for the benchmark firm. These unit costs should be used in the context of the AER's methodology from the April 2009 final decisions, which is based on benchmark cash flow analysis to determine the amount of retained earnings and the magnitude of the dividend reinvestment plan.

M.5.4 Benchmark cash flow analysis—implementation of the equity raising cost allowance

As discussed above, the DNSPs have adopted the benchmark cash flow analysis—as determined by the AER in its April 2009 final decisions—in order to determine the amount of equity raising required. In summary, the analysis calculated the amount of retained earnings (taking account of dividend reinvestment plans), which was deducted from the equity portion of forecast capex.

The AER has undertaken an assessment of the benchmark cash flows calculated in the PTRM by the DNSPs to model the equity raising cost allowance and considers some adjustments (as well as the adjustments to unit costs for dividend reinvestment plans and SEOs as set out in this appendix) are required. The details of the adjustments specific to each DNSP are set out in chapter 8 of the draft decisions.

Equity raising and capex forecasts

The AER notes the submission from the ECCSA regarding the interaction between approved capex and equity raising costs for ETSA Utilities. The AER considers that the application of its methodology ensures that the allowed equity raising costs reflect the approved forecast capex.[2554]

Amortisation of allowance

In its April 2009 final decisions, the AER adopted the approach to treat an allowance for equity raising costs as part of the RAB—that is, to amortise the allowance.[2555]

[2554] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 37.
[2555] See for example AER, *Final decision, TransGrid transmission determination 2009–10 to 2013–14*, pp. 96–97, 246.

This approach was consistent with the AER's previous treatment in the 2006 Powerlink transmission determination, which considered the benchmark cash flow analysis to determine the extent of equity raising cost associated with forecast capex for the first time. The AER considers that although the amortisation treatment is equivalent in NPV terms to a perpetuity income stream provided as part of the opex allowance, there are several advantages to this approach:

- it ensures a transparent link between the equity raising cost and the capex that required the equity raising
- it eases administrative implementation in future regulatory resets
- it implements the recommendation made by ACG.[2556]

In accordance with the AER's previous approach, the benchmark equity raising cost allowances for the DNSPs will be amortised over the weighted average standard life of their RABs to provide the equity raising cost allowance associated with forecast capex in the next regulatory control period.

Details of the AER considerations specific to the Qld DNSPs' proposed treatment are set out in chapter 8 of the Queensland draft decision.

M.6 AER conclusion

The AER has considered the arguments made by the DNSPs on equity raising costs, including consultant reports and submissions.

The AER considers that there is no evidence that the benchmark firm must use equity raising methods in market average proportions. The most relevant analysis of equity raising methods supports the AER methodology, with a hierarchy of retained earnings and dividend reinvestment plans, then SEOs (placements and rights issues).

The AER considers that there is no basis on which to accept an allowance for indirect equity raising costs. The AER notes that personal transaction costs are not an appropriate justification for an allowance under the regulatory framework. Similarly, the AER notes that arguments relying on wealth transfer between investors are not appropriate justification for an allowance, since the regulatory framework specifies investor return in aggregate.

The AER considers that the best estimate of the direct costs of raising equity varies depending on the method employed:

- 0 per cent of equity obtained via retained earnings
- 1 per cent of equity obtained via dividend reinvestment plans
- 3 per cent of equity obtained via external SEO (placements and rights issues).

[2556] ACG, *Debt and equity raising costs*, December 2004, p. xiii.

These benchmark unit costs include updates to previously applied figures based on recent data. The AER rejects the alternative estimates of direct equity raising costs proposed by the DNSPs on the grounds that they deviate substantially from the equity raising conditions relevant to the benchmark firm.

For each DNSP, the AER will apply the benchmark cash flow analysis and determine the amount that will be available from retained earnings and the amount reinvested via dividend reinvestment plans, and the amount of external equity required for the next regulatory control period from SEOs (placements and rights issues). Each component will be added to arrive at a total benchmark equity raising cost for each DNSP.

N. Alternative control services – quoted services

Tables N.1 and N.3 of this appendix set out the Qld DNSPs' proposed prices for their respective quoted services in the next regulatory control period. These prices were determined using the Qld DNSPs' proposed formula based price cap control mechanisms and are based on an illustrative (typical) service configuration.

Tables N.2 and N.4 set out the AER's approved prices for each of the Qld DNSPs' quoted services to be offered in the next regulatory control period based on the illustrative service configuration provided by the Qld DNSPs. These prices were determined using the AER's approved formula based price cap control mechanisms, as set out in chapter 18 of this draft decision, and each illustrative quoted service configuration. The AER's approved prices do not represent a binding capped price for an individual quoted service.

Energex

Table N.1: Energex proposed prices for quoted services (illustrative configurations) ($per service, GST exclusive).

Quoted service	2010–11	2011–12	2012–13	2013–14	2014–15
Rearrangement of network assets	3 906.43	4 166.11	4 376.54	4 592.88	4 699.80
Customer requested works to allow customer or contractor to work close	5 522.43	5 773.79	5 962.29	6 164.75	6 274.88
Non–standard data and metering services	106.04	114.37	121.29	128.30	131.66
Emergency recoverable works and rectification of illegal connections	8 699.53	9 301.61	9 793.60	10 301.36	10 570.27
Large customer connections	332 129.63	352 718.65	368 028.13	384 497.19	394 585.13
Design specification and other subdivision activities	1 272.53	1 372.46	1 455.46	1 539.63	1 579.90
Unmetered services, including street lighting	1 692.55	1 807.19	1 900.36	1 995.99	2 043.07

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
After hours provision of any fee–based service (excluding re–energisations)	1 523.17	1 637.54	1 732.59	1 831.82	1 893.07
Supply abolishment – complex	421.91	455.04	482.56	510.47	523.82
Additional crew	111.81	120.59	127.88	135.27	138.81
Temporary connection – complex	40 415.75	42 634.61	44 371.30	46 191.77	47 132.15
Loss of asset	6 401.95	6 593.73	6 792.13	6 997.41	7 209.86
Other recoverable work[a]	n/a	n/a	n/a	n/a	n/a

Source: Energex response to information request AER.EGX.25.05, 6 October 2009 (confidential).

(a) Energex stated that there is no common configuration of the ‘other recoverable work’ service. The service is applied only in those circumstances where the service requested is not covered by any of the other service categories or would not otherwise have been requested for the efficient management of the network.

Table N.2: AER approved prices for Energex’s quoted services (illustrative configurations) ($per service, GST exclusive).

Quoted service	2010–11	2011–12	2012–13	2013–14	2014–15
Rearrangement of network assets	3 660.74	3 858.79	4 006.97	4 161.20	4 209.75
Customer requested works to allow customer or contractor to work close	5 463.50	5 755.40	5 932.76	6 106.50	6 179.36
Non–standard data and metering services	98.10	103.45	107.88	112.61	113.90
Emergency recoverable works and rectification of illegal connections	8 152.84	8 587.85	8 923.97	9 281.04	9 406.48
Large customer connections	313 379.65	330 894.48	342 250.44	354 437.11	360 122.68
Design Specification and other subdivision activities	1 177.24	1 241.39	1 294.57	1 351.29	1 366.85

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Unmetered services, including street lighting	1 586.33	1 672.22	1 737.16	1 804.94	1 825.97
After hours provision of any fee–based service (excluding re–energisations)	1 424.43	1 497.33	1 557.70	1 625.00	1 655.45
Supply abolishment – complex	390.44	411.71	429.35	448.16	453.32
Additional crew	103.47	109.10	113.78	118.76	120.13
Temporary connection – complex	40 141.31	42 297.13	43 732.82	45 180.23	45 714.29
Loss of asset	6 174.53	6 141.92	6 109.99	6 078.76	6 048.20
Other recoverable work[a]	n/a	n/a	n/a	n/a	n/a

Notes: (a) Energex stated that there is no common configuration of the 'other recoverable work' service. The service is applied only in those circumstances where the service requested is not covered by any of the other service categories or would not otherwise have been requested for the efficient management of the network.

Ergon Energy

Table N.3: Ergon Energy proposed prices for quoted services (illustrative configurations) ($per service, GST exclusive).

Quoted service	2010–11	2011–12	2012–13	2013–14	2014–15
Design and construct of new large customer connection assets – worked example 1	204 572.36	218 110.12	231 653.94	245 525.75	260 303.44
Design and construct of new large customer connection assets – worked example 2	11 679 543.30	12 422 353.13	13 169 227.41	13 950 542.60	14 779 663.60
Design and construct of new large customer connection assets – worked example 3	12 743 252.22	13 552 327.23	14 362 709.92	15 208 678.34	16 105 902.59
Streetlight installation – worked example 1	1 677.90	1 748.50	1 819.72	1 886.84	1 950.71

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Streetlight installation – worked example 2	4 468.94	4 663.10	4 864.42	5 044.63	5 207.00
Streetlight installation – worked example 3	18 753.60	19 519.50	20 310.34	21 024.47	21 674.56
Streetlight installation – worked example 4	62 400.83	65 061.38	67 830.43	70 292.17	72 493.50
Removal or relocation of Ergon Energy assets at customer request	38 463.89	38 926.51	39 743.98	42 047.36	42 465.81
Relocate point of attachment	801.87	823.15	847.52	889.37	914.37
Tiger tails	475.21	487.36	501.29	525.17	539.49
Meter data service provider services	112.21	115.67	119.62	126.45	130.46
Meter data service provider services above minimum requirements	411.75	423.19	436.28	458.79	472.17
Meter test	451.93	464.61	479.10	504.06	518.88
Change tariff	284.47	291.98	300.58	315.35	324.18
Change time switch	142.24	145.99	150.29	157.68	162.09
Removal of meter	225.96	232.30	239.55	252.03	259.44
Removal of load control device	225.96	232.30	239.55	252.03	259.44
Special read	69.47	71.28	73.35	76.90	79.03
Reprogram card meters	426.71	437.97	450.88	473.03	486.27
Exchange meter	338.95	348.46	359.33	378.04	389.16

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Move meter	338.95	348.46	359.33	378.04	389.16
Connection service above minimum requirements	1 006.64	1 025.54	1 050.93	1 105.85	1 126.43
Overhead service upgrade	668.23	685.96	706.27	741.14	761.97
Underground service upgrade	4 817.98	4 888.72	5 001.42	5 291.84	5 360.25
Meter service above minimum requirements	846.18	860.32	881.16	931.21	945.65
Prepayment meters at customer request	1 164.84	1 188.30	1 219.62	1 287.13	1 312.54
Temporary disconnection and reconnection	338.95	348.46	359.33	378.04	389.16
De–energisation after hours	259.41	266.89	275.44	290.17	298.89
Re–energisation after hours	206.28	212.23	219.02	230.73	237.67
Attend loss of supply (not DNSP fault)	530.81	545.46	562.22	591.04	608.19
Emergency recoverable works	1 387.57	1 423.89	1 465.48	1 536.87	1 579.58
Subdivision fees	1 220.36	1 258.02	1 300.97	1 375.20	1 418.87
Project fees	469.37	483.85	500.37	528.92	545.72
High load escorts	6 414.63	6 605.87	6 824.20	7 200.98	7 423.37
Rectify illegal connections	585.38	601.86	620.70	653.14	672.40
Conversion of aerial bundled cables	953.96	974.80	1 000.57	1 050.41	1 074.15

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Provision of service or additional crew	355.59	364.98	375.73	394.19	405.22

Source: Ergon Energy, *Regulatory proposal*, July 2009, AR482c_EE_All Quoted Services_Summary_28May09_AER.xls (confidential).

Table N.4: AER approved prices for Ergon Energy's quoted services (illustrative configurations) ($per service, GST exclusive).

Quoted service	2010–11	2011–12	2012–13	2013–14	2014–15
Design and construct of new large customer connection assets – worked example 1	123 887.05	134 449.50	142 569.07	149 895.85	157 101.89
Design and construct of new large customer connection assets – worked example 2	7 438 867.55	8 025 761.91	8 488 559.02	8 916 393.26	9 341 583.03
Design and construct of new large customer connection assets – worked example 3	8 234 162.12	8 900 844.73	9 422 030.42	9 899 963.77	10 373 311.69
Streetlight installation – worked example 1	847.85	894.35	936.44	979.99	1 025.22
Streetlight installation – worked example 2	3 075.68	3 306.73	3492.00	3 665.93	3839.89
Streetlight installation – worked example 3	10 615.98	11 426.44	12 072.73	12 676.37	13 278.86
Streetlight installation – worked example 4	42 096.35	45 408.24	48 022.31	5 0441.03	52 845.69
Removal or relocation of Ergon Energy assets at customer request	24 665.59	26 446.92	27 787.83	29 502.11	30 582.63
Relocate point of attachment	411.42	425.71	441.81	460.83	481.46
Tiger tails	213.80	221.23	229.59	239.47	250.20
Meter data service provider services	93.94	97.20	100.88	105.22	109.93
Meter data service provider services above minimum requirements	254.84	263.69	273.66	285.44	298.22

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Meter test	274.28	283.81	294.54	307.22	320.98
Change tariff	142.53	147.49	153.06	159.65	166.80
Change time switch	71.27	73.74	76.53	79.82	83.40
Removal of meter	137.14	141.90	147.27	153.61	160.49
Removal of load control device	137.14	141.90	147.27	153.61	160.49
Special read	34.34	35.53	36.88	38.46	40.19
Reprogram card meters	213.80	221.23	229.59	239.47	250.20
Exchange meter	205.71	212.86	220.91	230.41	240.73
Move meter	205.71	212.86	220.91	230.41	240.73
Connection service above minimum requirements	542.78	573.97	600.21	632.96	658.09
Overhead service upgrade	342.85	354.76	368.18	384.02	401.22
Underground service upgrade	3 271.01	3 489.41	3 659.99	3 876.25	4 022.57
Meter service above minimum requirements	554.82	589.50	617.48	652.69	677.91
Prepayment meters at customer request	746.57	787.29	822.52	866.21	901.15
Temporary disconnection and reconnection	205.71	212.86	220.91	230.41	240.73
De–energisation after hours	204.89	212.01	220.02	229.49	239.77

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Re–energisation after hours	162.92	168.58	174.96	182.49	190.66
Attend loss of supply (not DNSP fault)	370.28	383.14	397.63	414.75	433.32
Emergency recoverable works	683.87	707.62	734.38	765.99	800.29
Subdivision fees	954.36	987.51	1024.85	1 068.96	1 116.84
Project fees	367.06	379.81	394.17	411.14	429.55
High load escorts	4 561.08	4 719.52	4 897.98	5 108.79	5 337.58
Rectify illegal connections	356.33	368.71	382.65	399.12	417.00
Conversion of aerial bundled cables	469.01	491.47	512.33	537.83	560.31
Provision of service or additional crew	178.17	184.36	191.33	199.56	208.50

O. Alternative control services – quoted services – confidential

P. Alternative control services – fee based services

Tables P.1, P.2, P.3 and P.4 of this appendix set out the Qld DNSPs' proposed price paths and prices for their respective fee based services in the next regulatory control period. Tables P.5, P.6, P.7 and P.8 set out the AER's approved price path and prices for the Qld DNSPs' respective fee based services in the next regulatory control period. These prices were determined using the AER's approved formula based price cap control mechanisms, as set out in chapter 18 of this draft decision, and represent a binding capped price for each fee based service.

Table P.1: Energex proposed price path for fee based services

	2010–11	2011–12	2012–13	2013–14	2014–15
Proposed price path for fee based services	As per price	7.32%	5.67%	5.69%	3.74%

Source: Energex, *Regulatory proposal*, July 2009, p. 327.

Table P.2: Energex proposed prices for fee based services ($per service, GST exclusive)

Fee based service	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Alterations and additions to current metering equipment	–29.03%	96.37	103.43	109.29	115.51	119.83
Attending loss of supply – LV customer installation at fault – business hours	–33.70%	108.05	115.96	122.54	129.51	134.36
Overhead service replacement – single phase	34.33%	292.55	313.97	331.77	350.64	363.76
Overhead service replacement – multiple phase	27.02%	344.97	370.23	391.22	413.48	428.94
De-energisation	–12.13%	47.75	51.24	54.15	57.23	59.37
Meter test	–14.43%	116.19	124.70	131.77	139.27	144.47
Meter inspection	0.00%	86.57	92.91	98.18	103.77	107.65

Fee based service, continued	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Reconfigure meter	30.74%	71.23	76.44	80.78	85.37	88.56
Off-cycle meter read	–63.80%	10.51	11.28	11.92	12.60	13.07
Site visit	39.94%	75.92	81.47	86.09	90.99	94.39
Locating Energex underground cables	0.91%	137.02	147.05	155.39	164.23	170.37
Temporary connection	30.60%	851.54	913.87	965.69	1020.64	1058.81
Re-energisation – business hours	–42.53%	41.61	44.66	47.19	49.88	51.74
Re-energisation – after hours	–6.52%	111.57	119.74	126.53	133.73	138.73
Re-energisation (visual) – business hours	–2.69%	70.46	75.62	79.91	84.45	87.61
Re-energisation (visual) – after hours	22.90%	146.69	157.42	166.35	175.81	182.39
Re-energisation non-payment (visual) – business hours	–2.69%	70.46	75.62	79.91	84.45	87.61
Re-energisation non-payment (visual) – after hours	22.90%	146.69	157.42	166.35	175.81	182.39
Supply abolishment	201.43%	328.07	352.09	372.05	393.223	407.9
Unmetered supply	–43.51%	153.46	164.70	174.03	183.94	190.81
Street light glare screening	2.65%	131.84	141.49	149.51	158.02	163.93
Replacement of standard luminaries with aero screen units (per street light)	–1.25%	299.98	321.94	340.20	359.56	373.00

Source: Energex, *Regulatory proposal*, July 2009, p. 326; and Energex, response to information request AER.EGX.05.06 (confidential).

Table P.3: Ergon Energy proposed price paths for fee based services

	2010–11	2011–12	2012–13	2013–14	2014–15
Escalator for subdivision fees and project fees	As per price	4.50%	4.50%	4.50%	4.50%
Escalator for all other fee based services	As per price	3.81%	3.81%	3.81%	3.81%

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 510.

Table P.4: Ergon Energy proposed prices for fee based services ($per service, GST exclusive)

Fee based service	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Subdivision fees	N/A	693.79	725.01	757.63	791.72	827.35
project fees	N/A	693.79	725.01	757.63	791.72	827.35
De-energisation during business hours – urban/short rural feeders	40.74%	118.06	122.51	127.13	131.92	136.89
De-energisation during business hours – long rural/isolated feeders	43.89%	564.91	586.21	608.32	631.25	655.06
Re-energisation during business hours - urban/short rural feeders	36.16%	93.88	97.42	101.09	104.90	108.86
Re-energisation during business hours – long rural/isolated feeders	43.60%	526.50	546.35	566.95	588.33	610.51
Re-test at customer's installation during business hours – urban/short rural feeders	67.10%	400.94	416.05	431.74	448.02	464.91
Re-test at customer's installation during business hours – long rural/isolated feeders	71.00%	801.87	832.11	863.48	896.04	929.83
Supply abolishment during business hours – long rural/isolated feeders	71.00%	801.87	832.11	863.48	896.04	929.83
Supply abolishment during business hours – urban/short rural feeders	67.10%	400.94	416.05	431.74	448.02	464.91

Fee based service, continued	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Temporary builders supply, not in permanent position– single phase metered – business hours – urban/short rural feeders	70.21%	668.23	693.42	719.57	746.70	774.86
Temporary builders supply, not in permanent position– single phase metered – business hours – long rural/isolated feeders	72.01%	1,069.16	1,109.47	1,151.31	1,194.72	1,239.77
Temporary builders supply not in permanent position – multi phase metered – business hours – urban/short rural feeders	70.21%	668.23	693.42	719.57	746.70	774.86
Temporary builders supply not in permanent position – multi phase metered – business hours – long rural/isolated feeders	72.01%	1069.16	1109.47	1151.31	1194.72	1239.77
Restoration of supply required due to customer action, during business hours – urban/short rural feeders	67.10%	400.94	416.05	431.74	448.02	464.91
Restoration of supply required due to customer action, during business hours – long rural/isolated feeders	71.00%	801.87	832.11	863.48	896.04	929.83
Wasted truck visit – one person crew – urban/short rural feeders	66.72%	86.20	89.45	92.82	96.32	99.95
Wasted truck visit – one person crew – long rural / isolated feeders	98.22%	344.80	357.80	371.29	385.29	399.82
Wasted truck visit – two person crew – urban/short rural feeders	52.34%	132.16	137.14	142.31	147.68	153.25
Wasted truck visit – two person crew – long rural / isolated feeders	68.28%	528.63	548.56	569.25	590.71	612.99

Source: Ergon Energy, *Regulatory proposal*, July 2009, AR443c_EE_Fixed Fee Services_Indicative Prices Calculation_2.xls and AR478c_EE_Fixed Fee Prices_Current Period_7May09.xls (confidential).

Table P.5: AER price path for Energex's fee based services

	2010–11	2011–12	2012–13	2013–14	2014–15
Price path for fee based services	n/a	4.91%	3.87%	4.28%	2.32%

Table P.6: AER prices for Energex's fee based services ($per service, GST exclusive)

Fee based service	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Alterations and additions to current metering equipment	–33.15%	90.78	95.23	98.92	103.15	105.55
Attending loss of supply – low voltage customer installation at fault – business hours	–37.65%	101.62	106.61	110.73	115.47	118.15
Overhead service replacement – single phase	27.30%	277.25	290.86	302.12	315.05	322.36
Overhead service replacement – multiple phase	20.31%	326.76	342.81	356.07	371.31	379.93
De-energisation	–16.93%	45.14	47.36	49.19	51.30	52.49
Meter test	–20.82%	107.52	112.80	117.16	122.18	125.01
Meter inspection	n/a	81.33	85.33	88.63	92.42	94.57
Reconfigure meter	23.23%	67.13	70.43	73.16	76.29	78.06
Off-cycle meter read	–65.11%	10.13	10.63	11.04	11.51	11.78
Site visit	33.32%	72.33	75.88	78.81	82.19	84.09
Locating Energex underground cables	–6.63%	126.79	133.02	138.16	144.08	147.42
Temporary connection	23.71%	806.57	846.17	878.92	916.54	937.80

Fee based service, continued	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Re-energisation – business hours	–45.73%	39.30	41.23	42.82	44.66	45.69
Re-energisation – after hours	–11.20%	105.98	111.18	115.48	120.43	123.22
Re-energisation (visual) – business hours	–7.75%	66.80	70.08	72.79	75.91	77.67
Re-energisation (visual) – after hours	16.79%	139.39	146.24	151.90	158.40	162.07
Re-energisation non-payment (visual) – business hours	–7.75%	66.80	70.08	72.79	75.91	77.67
Re-energisation non-payment (visual) – after hours	16.79%	139.39	146.24	151.90	158.40	162.07
Supply abolishment	187.08%	312.46	327.80	340.49	355.06	363.30
Unmetered supply	–47.73%	142.01	148.98	154.74	161.37	165.11
Street light glare screening	–0.59%	127.69	133.96	139.14	145.10	148.46
Replacement of standard luminaries with aero screen units (per street light)	–3.35%	293.60	308.01	319.93	333.62	341.36

Source: Energex, response to information request AER.EGX.35, 20 November 2009.

Table P.7: AER price path for Ergon Energy's fee based services

	2010–11	2011–12	2012–13	2013–14	2014–15
Price path for fee based services	n/a	3.47%	3.78%	4.30%	4.48%

Table P.8: AER prices for Ergon Energy's fee based services ($per service, GST exclusive)

Fee based service	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Subdivision fees	n/a	59.15	61.21	63.52	66.25	69.22
project fees	n/a	342.85	354.76	368.18	384.02	401.22
De-energisation during business hours – urban/short rural feeders	–29.48%	47.04	48.67	50.51	52.68	55.04
De-energisation during business hours – long rural/isolated feeders	–12.67%	319.54	330.64	343.14	357.91	373.94
Re-energisation during business hours - urban/short rural feeders	–31.78%	205.71	212.86	220.91	230.41	240.73
Re-energisation during business hours – long rural/isolated feeders	–12.85%	411.42	425.71	441.81	460.83	481.46
Re-test at customer's installation during business hours – urban/short rural feeders	–14.27%	205.71	212.86	220.91	230.41	240.73
Re-test at customer's installation during business hours – long rural/isolated feeders	–12.26%	411.42	425.71	441.81	460.83	481.46
Supply abolishment during business hours – urban/short rural feeders	–14.27%	342.85	354.76	368.18	384.02	401.22
Supply abolishment during business hours – long rural/isolated feeders	–12.26%	59.15	61.21	63.52	66.25	69.22
Temporary builders supply, not in permanent position– single phase metered – business hours – urban/short rural feeders	–12.67%	342.85	354.76	368.18	384.02	401.22

Fee based service, continued	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Temporary builders supply, not in permanent position– single phase metered – business hours – long rural/isolated feeders	–11.75%	548.56	567.62	589.08	614.44	641.95
Temporary builders supply not in permanent position – multi phase metered – business hours – urban/short rural feeders	–12.67%	342.85	354.76	368.18	384.02	401.22
Temporary builders supply not in permanent position – multi phase metered – business hours – long rural/isolated feeders	–11.75%	548.56	567.62	589.08	614.44	641.95
Restoration of supply required due to customer action, during business hours – urban/short rural feeders	–14.27%	205.71	212.86	220.91	230.41	240.73
Restoration of supply required due to customer action, during business hours – long rural/isolated feeders	–12.26%	411.42	425.71	441.81	460.83	481.46
Wasted truck visit – one person crew – urban/short rural feeders	–37.34%	32.40	33.52	34.79	36.29	37.91
Wasted truck visit – one person crew – long rural / isolated feeders	–25.50%	129.58	134.08	139.15	145.14	151.64
Wasted truck visit – two person crew – urban/short rural feeders	–21.58%	68.03	70.39	73.05	76.20	79.61
Wasted truck visit – two person crew – long rural / isolated feeders	–13.38%	272.12	281.57	292.22	304.79	318.44

Q. Annual reporting requirements

In a number of chapters of this draft decision, the AER has indicated that certain information will be required to be reported by the Qld DNSPs on an annual basis. This information is generally required for the administration of incentive schemes, to ensure the correct application of the approved control mechanisms, to monitor the performance of the DNSPs and for annual pricing purposes, amongst other reasons.

The purpose of this appendix is to provide a summary of the information the AER has indicated would need to be reported by the Qld DNSPs during the course of the regulatory control period to ensure compliance with the determination. The AER anticipates that some of the information indicated in this appendix would be reported annually for the purpose of ring fencing compliance or as part of a DNSP's annual pricing proposal. Otherwise, the AER anticipates that this information will be collected via a Regulatory Information Instrument at or around the time that annual ring fencing compliance reports are submitted by the Qld DNSPs.

TableQ.1: Annual reporting requirements

Chapter	Reporting requirement	Purpose
Classification of services – chapter 2.	Information relating to standard small customer metering.	To evaluate the maturity of the market to enable an alternative control service classification for small customer metering services.
Annual inflation adjustment – chapter 4.	The percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities from March in regulatory year t–2 to March in regulatory year t–1.	Adjustment to the maximum allowable revenue (MAR) each year.
Capital contributions – chapter 4.	Annual capital contributions in cash and contributed (gifted) assets.	Adjustment to the MAR each year.
Actual tax paid for 2008–09 and 2009–10 – chapter 4.	Actual tax paid related to standard control services.	Adjustment to the MAR for 2010–11 & 2011–12.
Actual use of shared assets for alternative control services by Ergon Energy – chapter 4.	A calculation of the revenues recovered by Ergon Energy through the actual use of shared assets for alternative control services.	Adjustment to Ergon Energy's MAR each year.

Chapter	**Reporting requirement**	**Purpose**
Forecast quantities – chapter 4.	Customer numbers, energy consumption, maximum demand forecasts for the coming year.	Conversion of the MAR to prices.
DUOS unders & overs – chapter 4.	Information as set out in Appendix D of this draft decision	Any under/over of DUOS charges in the past should be accounted for each year.
TUOS unders & overs – chapter 4.	Information as set out in Appendix E of this draft decision	Pass through of TUOS charges each year.
Ring fencing compliance – chapter 4.	Annual ring fencing compliance reporting against the applicable guideline and approved cost allocation method.	To ensure compliance with the NER ring fencing requirements and to ensure the correct application of the control mechanisms for standard and alternative control services.
Service target performance incentive scheme – chapter 12.	Report annual performance against the following parameters, consistent with section 3.1 of the national distribution STPIS: • Unplanned SAIDI • Unplanned SAIFI • MAIFI, as they are able to provide this information. The Qld DNSPs are to divide their respective electricity networks into segments by network type as specified in clause 3.1(c) of the national distribution STPIS for the purposes of reporting this information. The Qld DNSPs are also to report performance against the customer service parameter 'telephone answering'. Section 5.4 of the national distribution STPIS must be observed in determining events to be excluded for the purposes of reporting performance under the 2009–14 data collection process.	The AER will use the unplanned SAIDI and unplanned SAIFI to determine: • the penalties or rewards to apply by reference to the relevant performance targets set out at table 12.4 of the AER's Final decision. • the targets to apply for the 2015–20 regulatory control period. The AER will use Ergon Energy's customer service performance data to determine the penalties or rewards under the customer service parameter. The AER will use the Qld DNSPs' customer service performance data will to set customer service parameter targets for the 2015–20 regulatory control period. The AER may use the MAIFI data to set targets in future regulatory control periods.

Chapter	Reporting requirement	Purpose
Demand management incentive scheme – chapter 14.	Submission of annual report on demand management innovation allowance (DMIA) expenditure for each year of the regulatory control period. Details of reporting requirements are set out in Section 3.1.4 of *DMIS – Energex, Ergon Energy & ETSA Utilities 2010–15, October 2008.*	Ex–post assessment of expenditure and compliance with the DMIA criteria, and approval of expenditures.

Self insurance – Appendix K.	When a self insurance event occurs, the following information should be reported to the AER as soon as practically possible:
	• the nature of the event
	• the total cost of the event, identifying:
	    • costs that are provided for by external funding such as insurance or where the cost is paid for by third parties
	    • costs that are covered by self insurance
	    • costs to be passed through
	    • other costs, for example costs that do not relate to the regulated assets.
	• independently verifiable information/report to justify the estimated total cost of the event and funding components of the total cost that were used to cover the loss.
		The AER considers a prudent provider should disclose self insurance events each regulatory year and provide a brief description of the nature of the self insurance event in accordance with AASB 137 in its regulatory and audited financial accounts.
		AASB 137 requires the business, where practical, to also disclose an estimate of the financial effect of the liability, an indication of the uncertainties relating to the amount or timing of the outflow, and the possibility of any reimbursement.

Chapter	Reporting requirement	Purpose
Efficiency Benefit Sharing Scheme – chapter 13.	For each year, actual opex expenditure excluding the following cost categories: • actual debt raising costs • actual self insurance costs • actual insurance costs • actual superannuation costs relating to defined benefit and retirement schemes • actual Demand Management Incentive Allowance expenditure • actual non–network alternatives costs • actual costs of recognised pass through events.	Identify the proposed actual opex amounts attributable to each approved excluded cost category incurred during each regulatory year. Identify the actual total controllable opex for EBSS purposes after these exclusions. Determine the rolling carryover amount each year for the application of the AER's EBSS.
Pass through – chapter 15.	List and describe any pass through events during the reporting year.	Confirm whether or not a positive or negative pass through event has occurred during the reporting year. This reporting requirement is in addition to the requirements of the NER.
Alternative control (street lighting) services – chapter 17.	Prices for each street lighting service (contributed, non–contributed, major and minor) in the relevant regulatory year and the revenues recovered from the provision of those services as set out in section 17.6.4. The information should also include the volume of each non–standard street lighting service provided and the revenues recovered from the provision of those services.	Demonstrate compliance with the price cap control mechanism.
Alternative control (quoted and fee based) services – chapter 18.	The prices for each illustrative quoted service and the fee based services in the relevant regulatory year. The information should also include the volume of each individual quoted and fee based service provided and the revenues recovered from the provision of quoted and fee based services as set out in section 18.6.4.	Demonstrate compliance with the price cap control mechanisms.

R. Submissions

The AER received submissions on the Qld DNSPs' regulatory proposals from the following interested parties:

Energex (2)

Energy Users Association of Australia

Ergon Energy

Local Buy Pty Ltd

Local Governments Association of Queensland

Origin Energy Retail Ltd

Queensland Council of Social Service

Queensland Treasury Corporation

SPA Consulting Engineers (Qld) Pty Ltd

The AER also received a submission from AGL Energy Ltd regarding the negotiated distribution service criteria.